COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
Preparation of the 2007	)	Docket No.
Integrated Energy Policy	)	06-IEP-1F
Report (2007 IEPR)	)	
________________________________	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, MAY 10, 2007

9:00 A.M.

Reported by:
John Cota
Contract No. 150-04-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

Jeffrey D. Byron, Associate Member

John Geesman, Associate Member

ADVISORS PRESENT

Melissa Jones

Gabriel Taylor

Tim Tutt

STAFF and CONTRACTORS PRESENT

Linda Kelly

Rachel MacDonald

Jose Palomo

Lorraine White

ALSO PRESENT

Luther Dow, Pacific Gas & Electric (PG&E)

Bill Karambelas, FuelCell Energy (via telephone)

Russ Neal, Southern California Edison (SCE)

Tom Bialek, PhD, PE, San Diego Gas & Electric, (SDG&E)

John Westerman, University of San Diego, Energy Policy Initiative Center (EPIC)

Aaron Rachlin, Borderland Wind

Nora Sheriff, CAC/EPUC

M. L. Chan, PhD, KEMA, Inc.

Jane Turnbull, League of Women Voters

Steven Moss, San Francisco Community Power Electric Co-Op

Eric Lightner, United States Department of Energy (DOE)

Frances Cleveland, Xanthus Consulting International

Mark McGranahan, Electric Power Research Institute

Jim Skeen

Charles Toca, on behalf of VRB Power System (via telephone)

Peter Schwartz

I N D E X

I N D E X

P R O C E E D I N G S

9:11 a.m.

PRESIDING MEMBER PFANNENSTIEL: Good morning, I think we can begin. This is a joint committee workshop of the Energy Commission's Integrated Energy Policy Report Committee and Electricity Committee.

I'm Jackie Pfannenstiel. I'm the Commission Chair and the Presiding Member of the Integrated Energy Policy Report Committee. And to my right is Commissioner Geesman who is both on that committee and on the electricity Committee. Commissioner Byron, who is the Presiding Commissioner on the Electricity Committee will join us later this morning, I believe.

This is an opportunity for us to start to develop some understanding and strategies around the effects of the distribution system, utility distribution system. Of the many changes we're making elsewhere in the electricity infrastructure. And primarily distributed generation, renewable generation.

We all know that those will have effects on the, ultimately on the distribution system. And we also know, of course, that's where the connection to the customers is and that's where the issues and complaints are. And that as we work upstream that it will likely have some effects.

There's been a lot of work that's gone on nationally and in California on this subject and we wanted to bring it into the Integrated Energy Policy Report this year. So I thank everybody for being here, for being willing to share information and perspectives with us. By the end of what promises to be a very full and meaty day I think we'll all have a better understanding of where we need to go with this.

With that, Commissioner Geesman, do you have any comments?

Lorraine, hand it over to you.

MS. WHITE: Good morning. My name is Lorraine White, I'm the program manager for the Integrated Energy Policy Report proceeding and I welcome everyone as well to this morning's and today's workshop on the issues associated with California's distribution infrastructure challenges.

My job, of course, is to provide some of the announcements for the day. We here at the

Energy Commission want to make sure that your participation and your involvement in our proceeding is very active. We welcome input. We look very much forward to comments and questions throughout the day.

We have here at the Energy Commission some facilities that you may find useful for refreshments and such. Outside the double doors here we have restrooms both to the left and then directly behind the elevators. We also have on the second floor under the awning a little refreshment/snack shop so if you need water or anything like that you can get it there.

We have the materials for today's workshop out in the foyer covering all of the presentations and the agenda in more detail. We also have in the event of an emergency a protocol we'd like you to follow. In the event an alarm sounds we ask that you exit this room calmly and follow staff out the double doors here that most of you entered by the security guard. Proceed kitty-corner to the Commission to Roosevelt Park where we will convene and wait for the high sign to return.

For those who are here today we

encourage that in order for us to make sure everybody is heard that if you have comments or questions that you fill out blue cards that are on the table in the foyer and either provide them to Rachel or to Linda throughout the day so that we can provide them to the Chairman and have people called accordingly. We will be having an opportunity related to public comment related to the morning session as well as the afternoon session.

We are also providing this workshop through our webcast capabilities. Those who are also going to be participating in that, or via audio only, can call a toll free number. At the appropriate time we'll be asking folks in the call-in numbers or on the webcast if they have questions so you'll be able to participate that way as well. The call in number is 1-866-469-3239. But information is also available on the notice so you can follow the directions there.

We have also today the workshop being covered under the WebEx capabilities. That allows for much more dynamic participation as well. And in the notice there is also much more detailed directions on how to actually participate and hook in on the WebEx.

Just a couple of notes about our WebEx participation. We're following a particular protocol to make sure that we cover everybody and get the input we need. For those on the WebEx please use the raised hand function. There is a button there that allows you if you have questions or comments throughout the course of the workshop to indicate to our host your interest in making those comments. She'll be able to notify the Commissioners and at the appropriate time allow you to ask your questions.

So the order of the day will be questions and comments from the dais, of course. Attendees that are here in person, we ask that you please go to the podium there. And make sure that you press the button and have the green light on. Those who have raised their hand on the WebEx and then the phone-in-only participants.

As Commissioner Pfannenstiel indicated we do have a pretty meaty day and we look forward to having a lot of information discussed. The first part of the day will be covering the distribution system in an overview.

We have a panel also featured in the

morning after presentations by the utilities to provide us input on their distribution system operation and challenges and then a presentation on the San Diego Smart Grid Study Overview.

In the afternoon we'll be covering issues and topics related to technology innovations. We'll start off with information about what our PIER program is doing, the Public Interest Energy Research program, which has a distribution research program. And one of the topics that we're looking at there is the microgrid research. We'll have a couple of presentations there.

We also will be discussing research being done on the customer end and what the US Department of Energy is doing. We'll be looking at system integration issues and various types of emerging technologies related to the distribution system itself. And in the afternoon concluding most of these presentations will be the panel discussion on technology. We'll conclude with our public comment after that.

For those of you who have not yet been involved in the IEPR proceeding this is a legislatively mandated proceeding in which the

Energy Commission is to look at the energy system throughout the state, electricity, natural gas, petroleum, renewables, efficiency issues, infrastructure issues, the lot.

We began the proceeding on August 1 of 2006 and subsequent to that we began our data collection process, which will actually be continued through much of the proceeding so that we have a rich record on which to develop our analysis and generate our results.

From the staff's analyses results and input from various parties we'll be developing various issue papers that hone in on the specific topics, concerns, forecasts and analysis that the proceeding requires us to generate.

These papers then will be the foundation for us to develop policy recommendations and to generate the first of the IEPR documents, which is the Committee Draft of the Integrated Energy Policy Report. That we'll be producing about late August.

The Committee will hold various hearings on that as they have throughout this proceeding and ultimately issue a final Committee Draft in late October, in time for adoption by the whole

Commission on October 24.

We're legislatively mandated to transmit to the Governor and the Legislature by November 1st of every odd year this report and we are currently quite on track to do so.

All of the information about the proceeding is contained on our website. The site pathway is listed there. And that includes notices for other workshops, all of the supporting documentation, information on specific issues that the Committee is focused on. You can also get general information from me. My contact information is featured here as well as in the notice.

And then for those who are specifically interested in the work that PIER is doing, the content of this workshop and any of the other distribution related issues that we're working on you can contact Linda Kelly. That information is also in the notice.

With that, Commissioners, I will hand it over to Linda. If anyone has any questions on the process for today? All right.

MS. KELLY: Good morning. There was a lot of good information there, Lorraine, giving a lot of background on why we're here and what we're doing. And so I just wanted to make one comment.

I think that research in any industry is healthy and it helps identify issues early. I think for the PIER program this is something that we found. As we began doing our research assessments into the issues surrounding distribution I think we were able to identify a range of very important issues that needed to be addressed in the context of state policy. So I think that PIER has served a role in identifying early some of the issues that are really critical to policy.

We have a very busy schedule today so other than that comment I'm going to get right to introducing everybody and getting to the discussions. I'm going to start from the north of the state and I'm going to go south so we'll start with PG&E.

Luther Dow has worked with PG&E for over 27 years and he has worked in the public sector as well. He has also worked for EPRI and he has extensive experience in transmission and distribution. Luther.

MR. DOW: Good morning. Thank you for

holding this workshop. As the utility representatives of the PAC have discussed with you, we welcome the opportunity to share what we are doing and what our beliefs are on where the research and challenges are. So we look forward to the discussion. I'm sure it will be, it will be rich.

So let's just start a little bit out about PG&E. If I'm going to talk about the PG&E experience I have to at least talk about PG&E for a minute. We serve Northern and Central California, have a 70,000 square mile service territory, serve a population of about 15 million and have 5.1 million electric customers.

Since the service area is so large we have dense areas, urban areas, rural areas. Primarily residential customers and our important customers, of course, are our agricultural customers.

I want to talk about the distribution system and it is important that I go through this in a little bit of detail as to one of the areas of concern. To serve these five million customers we have 135,000 miles of distribution line. Seventy-nine percent of that is overhead.

We have 712 distribution stations, we have almost 2400 distribution banks, 2900 circuits changing daily. This time of year is when we're doing all our capacity work so that number probably will change twice before the day is over.

We have 2.3 million wood poles and we have 660,000 overhead distribution transformers bolted on those poles. And we have 200,000 underground transformers, either pad-mount or completely sub-surface transformers. And we have some 300,000 miscellaneous pieces of equipment that also contribute, capacitors, reclosers.

So you can see that it takes a lot, a lot of apparatus, a lot of components to make up the distribution system. So it's not only that we have a lot of them. I want to give you some age, average age. Our substation banks, those 2400 substation banks, have an average age of 43 years. That's the average age of those banks.

Our distribution breakers are an average age of 26 years. Our wood poles have an average age of 39 years. Our overhead distribution transformers have an average age of 36 and our underground transformers have an age of 18 years. So you can see that not only are there a lot of apparatus, there's also an aging apparatus.

I tried to think about how to describe the R&D needs in distribution and I've summarized them into three major categories. The first being the component condition assessment. How do we know that a piece of equipment is good or not? Oftentimes unfortunately we have to wait until it fails and that's not, that's not satisfactory to most anyone. So when I thought about where is the most important area, in my mind that is the most important area for research.

Also, how do we integrate DER in the distribution system? We are certainly supportive of that. If you look at the future of the system there is no doubt that DER is an integral component of that. How do we do that?

And then of course automation, distribution automation. There is a lot to be learned yet about how to automate the system and have it work later. So let me take a minute to discuss each one of these three areas.

As I showed, showed you just previously, there are millions of individual components. Each one of those components in turn have components so there are just a lot of things that can go wrong in the system. And as I showed you the age of the equipment is approaching the end of its useful life. So we need to find a way to identify how the various components are behaving and what the health of those, the health of those components are.

And I picked up two areas, sensor development application. There's a lot of need to -- and I think there is a lot of this sensor work going on. We had our PAC meeting last week. We had some staff from Berkeley there and they were talking about some sensor technology that was being used in the health industry.

And we thought well -- I was sitting next to one of the professors and I said, I'm trying to find a way, how can you put a sensor on a wood pole so that I wouldn't have to, so that I would know that that pole is going to fail. He said, maybe there's something we can do, there's some work that's being done elsewhere.

So we don't necessarily have to, we don't have to develop, necessarily develop the sensor but we have to be able to identify where the sensor technology is and then try to find out if there is a sensor there that we could use. So some sensor development/application.

And cable diagnostics is the other area. I want to talk about cable diagnostics. It happens to be something that I have a personal interest in. Let's talk about PG&E's underground system. We have 26,000 miles of underground cable. We have basically four types of cable. Obviously we have a spattering of other types. But if we were to take a look at our system we have cross link polyethylene, ethylene polypropylene rubber, high molecular weight and PILC or paper insulated cable.

Most of our cable is cross link polyethylene, 57 percent of that cable or about 15,000 miles. The estimated age of that cable is 20 years old. We have 27 percent of the system is EPR so that's about 7,000 miles. And the average age of that cable is five because that's the cable we're using today. We started using that about eight or nine years ago.

Then we have the older cable, older extruded cable, which is the high molecular weight cable. The average age of that is 35 years and we have about 4,000 miles of that. And then we have paper insulated lead covered cable, which is by far our oldest cable. The estimated average age of that is 40 years old and we have about 500 miles of that left in the system.

We have been doing some work recently to replace to that cable. That right now, that has been our focus on cable replacement. I expect another year of that and then we will, we will start to looking at other cable. So far PG&E has been replacing about 70 miles of cable a year. And if we have 26,000 miles of cable you can see that we are at a slow replacement rate.

The average cost to replace cable -- and this is to replace, not to install new but to replace. The average cost for us is running about $120 a foot. The range is from 80 to 150 normally.

ASSOCIATE MEMBER GEESMAN: You say a slow replacement rate. But if I do that arithmetic that's a 371 year --

MR. DOW: That's the same number that I've got.

ASSOCIATE MEMBER GEESMAN: That's not really a replacement program.

MR. DOW: That's a slow rate. You're right. But the question though is, are we replacing the right cable. You know, it's not age that is the issue here. It's how has the cable been operated, what is the physical environment in which the cable has lived its life. Has it lived in a very dry area, has it lived in a wet area. Has it had a lot of -- Is it an area where there's a lot of faults or is it an area that has been loaded, has been very lightly loaded.

So you have to -- The cable age depends upon how the cable has been treated. It's just like a human being. It's just like us. How have we treated our bodies and how we have lived our life. Now there's also some inherent problems. The type of cable also has some inherent problems just like our bodies have some inherent defects.

I want to make sure, I think if you press those numbers out, 70 miles at $120 a foot, that's about $45 million. I expect that that will increase substantially in the next few years. And we're okay with doing that provided that we're replacing the right cable. How do we know that we're doing the right work at the right place? We spend the money here and we have failures over here. Is that a good use of our work?

So there are two needs. There are two

needs that I see. And one of them is to be able to determine the health of the cable. And there has been a lot of work done on that across the nation. A lot of evaluating different types of tests and trying to determine how we can determine the health of the cable.

And in fact I think most of us when we look at trying to determine the health of the cable we do look at what type of testing can we do. What test is it that will tell us.

Well, in part of the PIER work we were looking at this slightly differently. We were looking at this saying, what type of sensor can we install that could give us some attribute or some attribute of the cable that we might be able to use. So rather than having to go out and do some testing maybe there are some sensors that we can install that will provide us some information. It's different from how I've been used to seeing that and I look forward to the way we're going to, we're going to proceed down that path.

Then once we've determined the health of the cable then how can we predict the remaining life. I think a lot of times when we do this work there's an inclination to say, well let's develop a new cable. We've learned all this stuff, how can we build a better, a better cable. That's nice and I think as long as it's, as long as it's an additional outcome that's fine. But the purpose here is not to develop a better cable, the purpose here is to determine how can we make sure we understand how our existing cables work and what we can do about them.

The next area that I believe we need to do some work in is how do we integrate distributed resources into the distribution system. There is no doubt that the distribution system of the future, DER is going to be an integral part of that system.

The distribution system of the future is going to be a partnership between the utility and the customer and it is going to be used by both the utility and the customer. It is going to be used by the utility to provide service and it's going to be used by the customer to provide energy into the grid or to customers or others. So we're both going to be using that system.

How do we do that? What are the -- How does that work? What does it mean when every home has a solar panel on it? What does it mean when every home has a solar panel on it and the inverter doesn't work? What does it mean when you have an outage and the person who has DER connected to his or her home wants to serve his neighbor or his neighbor wants to be served by him? That would make sense to do that.

So we really do need to understand the impact on the distribution system of further acceptance by the marketplace of DER. And there are adaptive protective devices that are necessary. As the load shifts we need to make sure the system is protected.

Microgrids. I'm convinced that microgrids are going to be a part of the distribution system. How do they work? How are you going to do that? How are you going to have a system that automatically separates from the system, serves a load and then when the system is restored can go back? There's a lot of technology there that has to be done to make that happen. But we need to do that because that's how we're going to, that's how we're going to allow the customers to fully utilize the DER that they're installing on their, on their facilities.

And the last piece is storage

capability. In my mind you have to be able to store energy and we need to have a way of having batteries or other storage devices that are connected to the distribution system. How does that work, how do we do that? So DER is an important piece.

Now the last area that I think is important is distribution automation. A lot of people talk about distribution automation and they say they have SCADA. SCADA is a subset in my mind. SCADA is a subset of automation.

If we want to improve the reliability, a step function, if we really want to say, if we want to go from here to here in my mind the way to do that is to automate the system. We can replace every component that's bad and we can continue to -- because every component contributes a little bit to the reliability of the system. So if we replace all of the cable we will incrementally increase the reliability of the system. If we automate the system, in my mind, we will, we will make a step function in that process.

PG&E uses, PG&E uses SCADA, mostly in substations, some field. We have developed, just completed a distribution automation roadmap that has provided us a long-term view of where, how we can implement the distribution automation into the PG&E system. That roadmap is --

ASSOCIATE MEMBER GEESMAN: Is that a public document?

MR. DOW: No, that process, that is just now going through the approval process.

ASSOCIATE MEMBER GEESMAN: When it is approved will it be something that we could get access to?

MR. DOW: I'm sure you could. But it's not, it has not been, it has not been approved through the process.

ASSOCIATE MEMBER GEESMAN: Sure.

MR. DOW: But we're there and we intend to do some automation somewhere in the system this year based on that roadmap.

So what are the needs there? Open protocols. We've all heard about the need for open protocols and operability with existing systems. All of the problems that pertain and there's a lot of work being done in lots of places about that. Lots of good work being done in lots of places about that.

Sensor technologies. Just like before,

when you have distribution automation you have the ability to have, to gather information about the health of your system. And we need to have sensors that help us do that.

Power electronics for rapid fault clearing and other types of operations in the system. We have a, we have a, we have a 21st century load and a 20th century distribution system. We have mechanical devices operating, spending time operating breakers and we have customers who don't want to see any interruptions. So we have power electronics to help us in that process.

ASSOCIATE MEMBER GEESMAN: You have a mid-20th century distribution system.

MR. DOW: We have a mid-20th century, thank you for the correction.

And again, we need adaptive protective relaying and we need to be able to anticipate the fault. There's a lot of nice work being done in EPRI and other places about trying to anticipate where faults may occur and being able to provide that information. If we can do that then we can provide that, we can sectionalize that piece of line. Automatically we can reconfigure the system and not involve an outage to customers.

PRESIDING MEMBER PFANNENSTIEL: Luther, how do you see the AMI, the advanced metering infrastructure that PG&E is moving rapidly towards, to affect this?

MR. DOW: I think AMI is going to provide, will be an input into the system. It will be able to take that AMI data and then be able to operate the system based on that AMI, that AMI input.

PRESIDING MEMBER PFANNENSTIEL: Will it change some of your thinking on the R&D needs?

MR. DOW: No, no.

PRESIDING MEMBER PFANNENSTIEL: These are then given AMI. This is what you still need.

MR. DOW: Yes.

Let me summarize and close this piece about -- I spent some time with EPRI doing research and I want to close with these thoughts about, about how I see research. There's a lot that can be done. Everybody has an idea and everybody has a good idea so there's just a lot of areas.

So you need to, you need to really focus on what's important. You need to get down and say, what are the, what are the things that are really, will really impact you, us or whoever is doing the decision-making. What will impact us. And focus on what's really important there.

Because it's really easy to step aside and say, isn't this cute. This is a really nice idea, it's really easy, I can do it very quickly, but now you've lost your focus on what is really important. So we really need to, we really need to stay on track with what's important.

And we need to -- There's not a lot of research dollars out there so we want to make sure that we don't duplicate that. We need to partner with others. The one thing that I really like in the PIER process is that they are partnering with other organizations, pulling together and joining and saying, they're doing that work, let us support them, let's join in with them, and I think that's a really important way to do that.

We need to continue regulatory support. We need to be rewarded for innovation and not penalized when some of this research material fails. Because research is that. Some of it is going to work and some of it is not. So we need the support of the regulators to be able to go forward and do, to be innovative.

We need the involvement of all stakeholders. That's another nice thing about the PIER process is that all of the utilities are here and we invite stakeholders and the stakeholders have a chance to speak. And that's, that's an important thing.

And finally, research is not necessarily a product. Research is knowledge. Research is learning how things work so then you can take the next step. And I have seen research programs fail because they promised a product. And they couldn't deliver on the product but they had really good information that could be used for other things.

And so we need to recognize that when we do this research it doesn't mean at the end of the day we now have, that we now have a device. But rather we have some additional knowledge on which we can build and then take the next steps.

And so I think that's the end of my presentation and -- Are we going to do questions later?

ASSOCIATE MEMBER GEESMAN: Luther, I wanted to ask you whether there are commonly accepted quality of service metrics applied to the distribution system, either internal to PG&E or within the industry overall?

MR. DOW: In PG&E we are looking, relooking at our reliability metrics. I think reliability metrics in general in the industry have been focused on the utility and not focused on the customer.

And we are, we are doing right now looking at various ways. And I'm sure that the metrics we have now are going to be different from the metrics we have next year. But I would say they are probably not.

There are some accepted ones but I don't think they're the right ones. If you really want to say, our job is to provide the best darned service we can to the customer, then those metrics are not good.

ASSOCIATE MEMBER GEESMAN: With the legacy system that you now have what's the trend line in terms of the quality of service metrics that you have been applying?

MR. DOW: The typical SAIDI and SAIFI, they have been declining.

ASSOCIATE MEMBER GEESMAN: And I would

presume with the aging nature of the infrastructure your projections are that that decline will either continue or accelerate.

MR. DOW: Unless we do something about it, and we are doing things about it. We're doing a lot to stop that decline. But you're right, if nothing happens, with status quo it will continue to get worse.

ASSOCIATE MEMBER GEESMAN: Thanks very much.

PRESIDING MEMBER PFANNENSTIEL: Two questions. First, is PG&E doing any of its own research in the distribution area or is it doing it through EPRI and working with PIER?

MR. DOW: It's not doing a lot. A little bit of definition of what is research, I suspect, but most of it is done through EPRI and through PIER. We are doing a few small products and trials but there's not a large research program.

PRESIDING MEMBER PFANNENSTIEL: And then the other question. You said at the outset that 79 percent of your system is overhead. Is that a fairly static number? Are you moving more towards underground, are you staying with overhead? I know the cost difference is enormous.

MR. DOW: Yes.

PRESIDING MEMBER PFANNENSTIEL: But how does the system seem to be going?

MR. DOW: Well the percentage is getting more underground, primarily because all the new development is underground. So the percentage of underground is getting larger.

PRESIDING MEMBER PFANNENSTIEL: And that's for new development. Are you seeing much in the way of undergrounding existing systems?

MR. DOW: Mostly through the Rule 20 process, the Rule 20A, 20B, 20C.

PRESIDING MEMBER PFANNENSTIEL: But is that significant? Does that really make any difference?

MR. DOW: It's a relatively small amount.

PRESIDING MEMBER PFANNENSTIEL: Thanks.

MR. DOW: Any other questions?

MS. WHITE: Just as a clarification, everybody knows that if you want to ask a question you fill out a blue card. We have no blue cards. We have nobody on-line. Is anybody -- Does anybody on the phone have a question? Hearing none I thank you very much, Luther.

MR. KARAMBELAS: Yes, actually I do.

MS. WHITE: Go ahead. Can you state your name.

MR. KARAMBELAS: My only question is -- Bill Karambelas, FuelCell Energy. I would just like to request if I could get the contact information for the presenter back up on the webcast so I can write down the information.

MS. WHITE: Okay.

MR. KARAMBELAS: Thank you.

MS. WHITE: All right. Just contact me and I'll make sure that you get this information.

Just as a point of clarification, I think as each of the utilities come up and make their presentation each of these presentations is very unique to the utility so I thought we would do questions in-between these presentations. And then during the panel discussion we can have broader, more general discussions at that time. But I did want to, as long as it wasn't too long, have questions in-between the individual utilities. So we'll proceed in that way.

Again, if you have questions please fill out the blue card and give them to Rachel right here or myself and then we'll pass them on to the Chairman. Okay?

All right, the next person is, moving down the state is Russ Neal. Russ Neal is the manager of distribution system planning for Southern California Edison. He is responsible for assessing load growth and sponsoring both load related expansion projects and infrastructure replacement projects for the distribution system, Russ.

MR. NEAL: Thank you Linda, Commissioners. This is going to be just a short presentation on the distribution system and some of its operations and challenges from our perspective here at SCE.

I would like to echo Luther's comments. We appreciate this opportunity to be able to make a pitch for the distribution part of the system which is sometimes seems like it's the bottom floor of the building is some ways and may not get as much visibility but it's pretty important for the upper two stories.

The distribution system, of course, is important because it represents the larger part of the T&D system. It represents 80 percent of the dollars that are sunk in the ground and steel, concrete, aluminum and copper.

We've gotten quite a bit of exposure to the fact that we have a very aggressive transmission building program in the next few years but out of our total ten billion dollar capital investment, capital budget over the next five years, 70 percent of that will still be in the distribution area. So it is still the whale in the bathtub financially speaking.

And of course the distribution failures account for 90 percent of customer reliability problems. That's the transmission system obviously networked and having some more redundancy in it. Individual failures there do not as often cause customer outages. But with the distribution system being basically radial, individual failures there do cause interruptions of service to the customer.

And of course we add a note here that the, there's reliance being placed on the distribution system and a lot of thinking going forward to be able to roll out, distributed energy resource solutions for some of our problems so that, that's an additional reliant which is being placed on that system.

From SCE's point of view, what are our priorities? What do we see as our big challenges. The priority and challenge that we've been experiencing most recently has just been to meet the load growth that we've been experiencing.

In the last few years we've had unexpectedly high growth rates that we've had to meet. And in our particular case it's significantly exceeded our projected load growth which was the basis of our rate case and our rates and put a great deal of pressure on the company to be able to meet that to some extent at the expense of the next bullet of maintaining reliability.

The issue here is that similar to what Luther was talking about of replacing this aging infrastructure. And some of our planned efforts in that area suffered as a result of the need to divert some resources to meet the unforecast load growth.

So we're quite concerned about this area of how we're going to be able to maintain that reliability going forward and of course the distribution cables are probably the single biggest component of our system of concern.

There's one extra item that I did want to touch on here today which is this subject of air-conditioner stalling which is kind of something we're beginning to identify now as a threat to both the power quality and potentially to the reliability of the overall system. And I'll be speaking about that in a few moments here.

And then finally, we understand that being pressed on all sides the one hopeful thing that we do have is emerging technology may enable us to be able to get through some of these thing. So we wish to be able to explore the technological avenue of solving some of these problems more aggressively.

I'm going to be sharing a little bit here on one thing that we're doing at the distribution level there that which call our Avanti circuit. Or sometimes we call it our circuit of the future.

Where we've simply taken one of our distribution circuits that we're building out of the many we build every year and we've set it aside as sort of a technological showcase or a vehicle on which emerging technology can be tried out.

And so different types of technology can be, have integration efforts worked out that particular circuit.

On the subject of cable this particular histogram shows how many conductor miles of the various types of cable that we've installed similar to, somewhat similar to the ones that PG&E has. There's one difference to it.

We start with the paper insulated lead covered cable right here which was the historic type of cable. We had a little experience with the high molecular weight which was not very favorable. So we got away from that and settled in on cross-linked polyethylene cable which is the bulk of our installation.

` Our installation is a little bit different than many others. We have a lot of this. Almost all of this is unjacketed. And almost all of it is either in conduit or in what's called CIC or conduit in cable which is like a softer conduit that's laid in the trench at the same time as the cable.

That's not as common, that's not the most common way it's done in the industry.

And we've migrated recently to an upgraded cable which is called tre-retardant cross-linked polyethylene as opposed to the EPR that some other utilities have gone to.

We also have decided to go with putting jackets on it at this time and doing some other upgrades to the cable based on the fact that the people right here are having to live with the decisions made right here, right now. So we're trying to do a little bit better for our descendants.

ASSOCIATE MEMBER GEESMAN: What does the jacket do for you?

MR. NEAL: The jacket provides physical protection to the working parts of the cable. The cable itself, you have the central conductor, then you have an insulating material. And then there is like a, on top of that is what's called a shield type of material.

And that physically consists of a semi-conduction poly black plastic, polyethylene that's extruded in a thin layer on top of it. And then you'll sometimes see a, you'll always see in our case copper wires wound in a spiral around that.

That produces a ground plane around the

insulation so that the real insulation, the cross-linked polyethylene will feel a geometrically even distribution of voltage stress on it so you don't have stress concentrations at different points which lead to the failure.

During installation of these cables it's possible for that jacket to get slightly damaged. It's during the service life that that concentric neutral copper wire is subject to corrosion. And the jacket reduces both of those two effects which can be contributors to cable failure.

In particular when that concentric wire deteriorates it's used to carry some of the ground return current back to the substation if you want to think of it that way. And when that is deteriorated some of that return current finds its way back to the substation through the earth.

And that sometimes results in the complaints that you hear about stray voltage. And sometimes has an effect especially on like dairy production. And it can also result in people experiencing some shock potential sometimes. In particular if the plumbing in the house is different than the doorknob in the house and sometimes you can have some electric shock hazards from that.

We also, I'm also of the belief although we haven't proved it, but that also contributes to the subsequent deterioration of the cable because of the current trying to get past these areas of failed concentric wire.

This particular graph shows our calculated, our assessed prediction of cable unreliability it's called. In other words, when will it fail? Down in these years it won't fail. It's got like a zero chance of failing. And out here it's a 100 percent chance of failing.

And this shows the four types of cable that we were talking about. And of course the cross-linked poly being the major one here, about a 50 percent failure probability is somewhere in the 35 year time frame.

We took those two pieces of information, the histogram that says what's out there and how old it is and we took those failure prediction curves and we have done a study that says what will be the projected impact on our principal measures of reliability, the SAIDI and the SAIFI.

So this other curve shows what we project for the SAIDI or the duration issues.

Right here we're at 2007 we're experiencing a number like 60, 63 minutes as an average number of minutes customers experience their outages.

We show a number of the factors that contribute here, storms and so forth as being flat lined. Some of the equipment reliability issues will be getting worse in the future no matter how well we do even in a fairly optimistic case of replacing equipment.

And then these top curves here from the purple one and the green one represent various cases of cable replacement programs.

So if you do no cable replacement and allow it to run to failure you'll be running on that top curve, the top of the purple. And then various things running from a 100 mile per year up to a 600 per mile year of cable replacement are shown down here.

In the worst case you would basically in the next 20 years you would double the SAIDI numbers that the customers are experiencing if we do nothing. We're not doing nothing right now. But that's probably the curve we're the closest to.

And this is the same thing for the SAIFI or the frequency at which people are experiencing these interruptions. And in that case it's similar but in 20 years people will be experiencing about 50 percent more than they do today if we don't do anything.

Even if we have a very aggressive 600 mile a year rate which is more than 10 times anything we've ever done, if we had that and sustained that for this next 20, 30 years you're still seeing the situation get worse every year even under a highly optimistic situation like that.

The subject of air conditioner stalling is something we've observed, It turns out that small capacity, less than 15 ton air conditioner compressors, stall on momentary voltage dips.

Actually they all stall, but the larger ones are always equipped with an under-voltage trip device that removes them from the system when that happens.

The reason they stall is because once they're running that compressor has pressurized gas in it. The motor no longer has the ability once it stops to restart in that condition. It has to wait for that to bleed off before it's able to restart.

Because what happens to the smaller ones is they'll stay connected to the system trying to turn, unable to turn, and what removes them is their thermal overloads over a certain number of seconds or minutes, well seconds really that they actually remove.

They then reset themselves. The customer never knows it happened. But the system might know that this had happened if it's a large percentage of the connected load at that time.

It can cause a slow voltage recovery. And in the extreme case it could even threaten system voltage collapse. I mean potentially throughout the entire connected western grid. But that would be an extreme case of it.

We're actually, one of the issues is in attempting to model that we're very uncomfortable with our models. The PIER program, the transmission road is doing a lot of work in that area to try to improve our modelling capabilities so that we have a better idea of what we're dealing with here.

An ultimate solution to this would be to actually install under-voltage trip devices on these smaller air conditioners the same way it is on bigger air conditioners.

An alternative to trying to fix it at the utility system level appears to be technically not feasible. One of the questions we're wrestling with right now and we've been having some discussions with Commissioner Rosenfeld especially about this issue and we went back and talked to FERC Commissioner Wellinghoff also about this.

Is what regulatory or legislative venue would be the right way to go forward with trying to get something like this included in residential air conditioners. That's one place we're at right now.

This shows what I'm talking about. This represents the voltage that you're experiencing on a distribution circuit someplace. And let's say at the transmission or sub-transmission level there's a momentary fault what would normally occur is that fault would drag the voltage down very low but then within like a tenth of a second or so that would be cleared by the transmission breakers and voltage would pop back up to one and this would just be a down glitch that people would barely feel.

But because air conditioners stall during this time if you have a large number of them stall on the connected circuit the voltage will not fully recover until those thermal overloads remove it over a period of time.

This shows a period of about 20 seconds here to get back during which time the system was trying to correct that voltage so there's an overshoot due to load tap changers, capacitors, that sort of thing. And there can be complications down stream.

And an extreme case of this could lead to a voltage collapse. That's what we're looking at.

ASSOCIATE MEMBER GEESMAN: Have you always experienced this phenomenon in the air conditioning portions of your service territory?

MR. NEAL: The first recorded, the first thing I've been able to find in writing on this was a case, and I believe it was Tennessee in '86. And there's a paper on that. The first time it came to our consciousness we had an event '96 when an airplane hit a 500 kV line.

And we had this situation over a wide

area of our system for more than 30 seconds, very noticeable to our operators who were just biting their fingernails of watching this voltage try to crawl back up.

By the time we did recover we had lost 3,000 megawatts of load. So it was a huge event to us. And it got us worried about this.

But then we started looking at it much, much more closely and started seeing it all the time. But most of them would be like five second delay that's from 95 percent and you wouldn't have ever noticed it if you weren't looking for it.

So we've been aware of this for some time. We observed in the summer of 2005 about three events that came to our attention. This is one of them.

And then last summer we recorded 30 of them. I'm not sure how much of that represents the increase in incidence and how much of that represents the fact that we were looking a lot harder.

But I do know that we have been experiencing a lot of this residential construction on circuits where a lot of the load is air conditioning out in hotter areas. And so there, that sort of thing is happening.

Like I said, most of these occur when you're having, we don't have a whole lot of 500 kV faults occur at just the right time. And because our models are so-so we really aren't really completely certain how much risk is involved with this under a worst-case scenario.

ADVISOR TUTT: I take it that this has nothing to do with the type or vintage of air conditioner?

MR. NEAL: It has a little bit to do with it. The newer high efficiency are a little bit more subject to this. But they're all subject to it.

PRESIDING MEMBER PFANNENSTIEL: And explain what is the technological fix. You said that you know how to fix it.

MR. NEAL: Yes, at the air conditioner you would have to have a sensor which is observing the voltage dip. And if it dips below a certain threshold for a certain amount of time it would disconnect the compressor from the system at that time. It would not wait for it to heat up and disconnect over many seconds. It could remove it in less than a second, right away.

But that has to be at the air conditioner to do it. The alternative of dropping entire circuits is not much of a solution.

I mentioned that in the technology area we have what we call our circuit of the future, the Avanti Circuit. And as I've said I've described this a lot of times to people as a Christmas tree on which you can put ornaments.

It's a regular distribution circuit coming out of one of our substations in the city of San Bernardino. It should be in service in July of this year.

And it is being built to have the capacity to accept various types of emerging technology to allow us to test it out.

So for example, we're installing a fiber-optic duct temperature monitoring system. We have a cement pad here with a by-pass switch that will accommodate a fault current limiter that the Energy Commission is working with EPRI to develop.

And there are several other developers that we're working with. And so the circuit is built such that you can put one in, try it out for a period of time, swap it out without interrupting anybody's load. There's that type of a thing.

We have a facility to allow connecting various types of stored energy or distributed generation to the circuit with communication back into the substation and SCADA system to try out different paradigms in which the DG is not merely riding on our system but is actually can be treated as a system asset in some way, through some type of control paradigm that is yet to be worked out.

Places where today we just have ordinary switches out there we're putting in vacuum fault interrupters. Normally you couldn't put many of them in line with each other because you couldn't coordinate them.

You wouldn't get the advantage of only the downstream one tripping. They would all trip. But what we're doing is stringing fiber optic between them allowing them to communicate and thereby achieve coordination where with old technology you couldn't do that.

We have some things shown on here that we're not really doing yet but there just a twinkle in my eye. Like some little spot secondary networks in a customer so a customer would receive no interruption every time a primary circuit interrupts. Most customers would not experience an interruption.

We're looking at something better than just capacitor banks for the reactive power support. Right now we're looking at a type of a distribution level, what they call a static VAR compensator which is a bunch of capacitors switched in and out by solid state so that you can ramp in and out the capacitance.

One thought is, you mentioned the issue of power quality concerns that customers are having. A fault on another circuit over here is felt by all of these poor guys over here.

If you just put some simple impedance in the area here like a reactor, a coil of wire, and if this was a fast reacting static var compensator it might be able to buffer this circuit so that it would not see the voltage dip so bad. So maybe if before it would have seen a 20 percent voltage dip now it will only see ten.

And that might make all the difference to some customers who have ride through issues with sensitive equipment.

And then we show that perhaps some early deployment of AMI and how that might coordinate. How distribution transformers might be able to phone home to our system through this communication links.

There's a lot of things that we are doing here. And the way we're approaching this particular circuit is we're providing the Christmas trees. We're looking for other people to provide the ornaments. We're trying to partner with vendors, with resource organizations, with DOA, with CEC, with whoever and provide a platform for these type of collaborative efforts.

And so in conclusion I just would point out that the distribution system represents the largest part perhaps of the, at least of the T&D system, maybe the whole power system.

Its performance primarily defines system reliability from the point of view of the customer. And that public policy needs to recognize its importance by supporting cost recovery for planned investments and perhaps helping us with these air conditioning codes and standards issue.

I'd like to just also touch on the one issue that you brought up with Luther there which is the research funding. of course the way that utilities make money is we just get a certain percent of return on our capital investment.

And R&D is of course an O&M expense. So effectively it's money just taken right away from the shareholder in exchange for which they have no opportunity to make any profits. So there is a lot of dis-incentive there.

In our current rate case before the Public Utilities Commission we're going to be asking for some additional funding there.

The funding we do through PIER I think is very good. I think all of us have really benefitted if nothing else from the fact that you got us all together. So that Luther and Tom and myself can sit around a table and discuss what we're doing. And there are some efforts that we've initiated that really, none of us as an individual utility would have undertaken. And so as a collaborative it's good but the flip side is that when utilities have their own funding and their own manager and their own research, they can move a lot faster on a lot of other little projects that might have some pretty good quick pay off.

So that's the conclusion of my presentation and I'm happy to take any questions.

ASSOCIATE MEMBER GEESMAN: Russ I want to thank you for your presentation and also to just reiterate to you that the Avanti Circuit is a very high priority PIER project and something that we've benefitted from in its early stages and hope to see blossom quite a bit more in the future.

Commissioner Rosenfeld and I on the R&D Committee have previously tried with not much success to encourage our colleagues at the PUC to support the transmission R&D activities of your company.

I think that the same applies in spades with respect to the distribution efforts. And we're happy to extend that as yet unproven offer of assistance if you feel it can be of benefit.

I do think that given the reliability projections that you and other companies in the industry are making in terms of future from a customer perspective really underline the need to do a lot more in this area.

And I'm confident that over time our colleagues at the CPUC will recognize that as well.

PRESIDING MEMBER PFANNENSTIEL: Any other questions?

MR. NEAL: Are there any other questions Commissioner?

MS. KELLY: Any blue cards, are there any blue cards.

Unidentified audience member: I have one but we'll be back in the pm.

MS. KELLY: Oh, okay, fine. Any questions on the telephone?

UNIDENTIFIED TELEPHONE SPEAKER: No we're okay.

MS. KELLY: Okay, thank you very much. Thank you Russ.

MR. NEAL: If you'd indulge me for just one more comment I would like to be able to make. The state is moving down the road now to make some very significant investments in the area of generation and transmission.

And we just don't want to be the last one to the trough to get funded for some of these distribution issues (laughter), thank you.

MS. KELLY: Thank you Russ.

ASSOCIATE MEMBER GEESMAN: Well I guess I can add to that. Your trough is proportionately larger than any other aspect of the capital budget within the industry in California and elsewhere.

And it's incumbent upon government to make certain, we're putting a high quality of pretty modern feed into the trough. It doesn't make a lot of sense to simply rely on 1957 Chevy technology. It was a great car. But it's not particularly well designed to the needs that we face in the future.

MS. KELLY: Thanks Russ. The next presenter moving all the way down the state, we're now down in San Diego. Tom Bialek has more than 22 years experience in the design, development, evaluation and applications and testing of electric power equipment and the electric grid.

His present responsibilities include technical oversight role on transmission and distribution issues including equipment, operations, planning, distributed generation and development of new technologies, Tom.

DR. BIALEK: Thank you Linda. Thank you Commissioners for having us here today. Again I'd like to also reiterate that we the IOUs in California really do appreciate the opportunity to come here and talk about distribution issues.

I think that you will see from my presentation, you're going to hear a lot of the same kinds of things that you heard from both Luther and Russ.

Particularly in regards to what the distribution system is, what it does. I went off here earlier sort of draft that Linda had as far as sort of an outline. And so I will probably talk about a little bit different subjects than perhaps Luther and Russ had talked about.

So here's an overview of my presentations. What I would really like to first touch on is what, issues in regards to the distribution system.

Really the aging infrastructure and maturing workforce. Not only do we have a aging infrastructure simultaneously we have a maturing workforce as well.

Utilization of distribution automation, what that means both SDG&E as well as beyond, further applications.

Talk a little bit about communication control technologies. You may think that we're an electric power utility but in some respects we also got a very large communication and sort of communication technology infrastructure as well.

Integration of DER by SDG&E and end users. A little bit about the San Diego Smart Grid Study because we are one of the co-funders of that particular study.

I would like to talk about service reliability levels.

And then lastly from our perspective and a concluding perspective, talk about what we see as from an SDG&E perspective, public policy support needs.

So I'm not going to go into a lot of detail. You've heard a lot about how we've got transmission, you've got distribution systems. You can see here our statistics. One of the things here to point out is that based upon our FERC FPR, 1 filing ratio the installed distribution and transmission plan equals 3.2.

We've got a lot of miles we're the smaller utility IOU in California. But you can see the same kinds of issues.

What I would like to spend some time with here and here is some graphs and a little bit of a different presentation versus what you saw from both Russ and Luther.

What you've got in these cases are distribution 12 kV banks and here is our poles. And all I've plotted here is the cumulative percentage in this case of banks and in this case of poles versus age. And really the point to take away from this is that, you know, realistically the infrastructure is aging. And it's aging fairly significantly.

In our particular case 32 percent of our 12 kV banks exceed 40 years of age. And 49 percent of our poles exceed 40 years.

Now moving on to what is usually the favorite subject, cables. Same kind of issue with cables.

What's plotted over here is actually our predictions of actual cable failures with 90 percent confidence bounds as well as the actual failures that are in there.

So what you see is that again in this case 18 percent of our cables are at least 30 years old. We're seeing increasing failure rates versus time.

But what we're seeing is particular vintages of cable are really the drivers behind this upturn in cable failures.

Clearly the replacement costs of all the banks, poles and cables that we have today is huge for us. Something on the order of 4.8 billion dollar investment just in those particular areas.

And if you just took an age perspective on all of this and said I'm going to cut at 40 years for banks and poles and 30 years for cables, you're talking on the order of an investment of about 1.8 billion dollars.

So clearly we at SDG&E believe that we think that better tools, technology and systems can help optimize our system replacement.

We have built into our reliability analysis some predictive reliability assessment tools. We have built in the ability to be able to sit there and look at cables and cable failures on an individual vintage basis.

We believe that things like condition based maintenance will help a lot. I mean age is clearly an issue but it is not the issue.

So knowing what the condition is. And then looking at diagnostic tools. Luther pointed out the need for diagnostic tools. Cable in particular or any of the other pieces of equipment we have.

What we really want from a diagnostic tool perspective is a tool that can be utilized on line as opposed to taking outages. Customers are already experienced in outages and so what we would really want as far as sort of from an R&D ideal perspective is a diagnostic that can be utilized on line. Avoid the taking it out of service for test and the development of analytics.

So we believe that really those four things really are going to help us and have shown some real help and aid for us at SDG&E particularly with regards to overall system reliability statistics.

So we actually have a fairly, we've had a fairly aggressive practical cable replacement program since the early 2000s, somewhere approaching a hundred miles a year.

And our original focus was on the main feeder cables. That's where typically the impact on customers is largest. But what we're seeing now is that we have replaced a lot of that cable. And so it's all relatively new.

Where we're seeing the failures now is our laterals or branches where we have a much smaller amount of customers.

So this graph here now, it's a few years old but it basically sits there and looks at to compound the problem, you can see here the three different curves.

And you've got all employees and you've got union and non-union. And what we're seeing is that a significant amount of skilled employees are retiring.

And so really, the real issue is how to transfer the knowledge, how to improve productivity and how to, and we believe again, the solution is tied to use of new technologies and use of automation and other investments in R&D.

One of the things that we're also seeing is, particularly for power engineers, there's really not a large amount of power engineers coming out of the university systems these days.

So what we're seeing is, we're going out and hiring new graduates as opposed to experienced employees. We have a difficulty doing that because when they come to California they all sit there and say, you want to pay me how much, look at the house costs.

And so we get them out there. We get them out for the interview. They have a nice time in San Diego and then they turn around and say, you're not going to pay me, you know, 200,000 dollars a year, guess what, I'm leaving.

The other thing that we're seeing lately is that a lot of the young engineers that we have brought out get five or six years of experience under their belt and then they start to get scavenged by other either utilities or other vendors or other business streams that need experienced employees.

Well let me switch gears a little bit to distribution automation. Particularly we're talking about in this particular case, SCADA.

You can see here these are our numbers sort of at the end of 2006. But I think one of the key points to take away from this and I'm not going to read all the points here but, we use it to help plan and design. And we use it to remotely operate. So from a system operation reliability perspective we think that that is very important. And we can use it also to diagnose and solve system problems.

We started our SCADA installations in '95 with a significant wrap up in '99. We have a preferred design that basically is a SCADA auto substation circuit breaker. And it's called one and a half design.

We've got a mid point service restorer on SCADA and an open tie on SCADA.

And I think as everyone has pointed out one of the big differences between distribution, transmission is that the network versus the open loop design that is typical of distribution.

So we feel that with an open loop with a circuit tie to adjacent circuits in most cases we're able to pick up customers when there is a fault. And so we can minimize the impact to customers.

Also what we believe is that we're in the process as Luther also mentioned of doing automation trials where we'll actually fully automate the switching that occurs.

Today given historical reasons and safety reasons our operators are very reluctant to actually switch automatically a closer or a breaker that may have opened. They will typically call for a trouble men to get out there.

And the trouble men will then sit there and tell them where the problem is, where the fault is. And tell them whether it's safe to restore service via a SCADA device.

In some instances of course what that adds is additional time to get the manpower out there.

And at the transmission level and substation level that's actually really problematic for us because we have bus ties between adjacent banks and because of the risk of bus fault in the substation we will actually send a crew from our Kearney Substation Operations group to the substation to check and make sure there wasn't a bus fault before we actually close that bus tie and pick up load.

That's typically like a half hour operation given our service territory or longer.

One of the other things that we see with automation is that it will in the future allow better integration and control of various DER alternatives that are out there both from a SDG&E utilization perspective but also a better integration of customers into the system to allow all the future opportunities that we see are coming down the road for customers.

One of the keys about distribution automation is not just, it's not just the switches. It's all the other stuff as well.

There's the sensors, the systems, the analytical capability behind it which to a large degree hasn't necessarily evolved to the point where like I said, we're just starting down the automation path.

But we've got a lot of SCADA out here already. Why don't we have a system in place today that doesn't operate in an automated fashion? Because of some of the issues with regards to the analytical capabilities and putting that in place.

And then one of the other things that we will be doing with distribution automation as well and some new systems that we're putting in place is the inclusion of the AMI data imports.

So we see that as enabling us to better isolate those customers who are upstream of a faulted section and can be restored.

So I did mention the fact that we do have quite a bit of communication control technologies within our system. We do have extensive radio, microwave, satellite, telephone and fiber optics.

We have in the last couple of years

piloted five first generation broadband over power-line technologies in San Diego.

We are currently embarking on a five year installation of a fiber network between substations to better allow high speed connectivity between basically the relays within the substations themselves.

We see that there are some real future challenges for both AMI and Smart Grid applications for communications.

One of the real keys I think is just the whole interfaces to new, actually to both the new and the legacy systems and particularly the legacy systems.

We've got an installed base that is typically looked at as being a 30 or 40 year of lifetime. We are clearly not turning those over in any appreciable time frame that would renew the system in five years.

It's going to be a much longer term issue. So the question is you've got all this older technology sitting out there and if I want to put sensors and I want to automate and I want to do partition based maintenance, how do I get on to that equipment. And then how do I get it back to the systems, the numerous systems that we're going to put in place.

And then just as you are aware the whole issue with regards to open communication centers. How is that done?

One of the big differences between the sort of power system if you will, versus the communication systems and IT systems is just the fact that there is such a rapid refresh of technology.

Our IT people are talking about a total network refreshing of just five to seven years. So the question is given that how do you actually go ahead and make sure that the next generation of technologies that you actually put in place will be able to pick up and take over where you were before. And so open communication standards is the key.

This is a little bit of a busy graph but I did want to provide a little bit of information here. This is just for the people that are out there this is the historic, what we're calling DG applications in San Diego County.

And I've put it in here just to provide some level of visibility as to where DG installations are and in particular DG sort of classified as ten megawatts or less and primarily in this case gas fired.

Because from a numbers perspective the photovoltaic installations in San Diego County far exceed the DG installations.

But the predominance of and this is supposed to be the year and this is supposed to be the number, pretty amazing enough people looked at this and that one still got through. What we see is a predominance is in the less than 500 kilowatt range.

And then the next biggest one is in the thousand kilowatt range. So a lot of relatively small particularly CHP kind of applications.

I pointed out here in particular and now looking at it from a SDG&E perspective I point out Public Utilities Code Section 353.5.

And the reason I did that is because it does have a mandate in there that the utilities look at DER alternatives to provide the lowest cost solution.

We at SDG&E really do take that to heart. We have developed electrical standard practices to look at incorporating DG as a an alternative. And it's actually based upon our mobile, rental mobile generators which in many respects is actually the lowest cost kind of technology that would compete against a wire solution.

Some of the other things that we have done. In our last rate case filing we implemented a program called Sustainable Communities. It is a bigger, broader based than just strictly energy from SDG&E or electricity. It's also on water. It's also on sewage. It's basically whole building design standard practices.

And we were able to get that funded through the CPUC. And what we have done with that is we have looked at evaluating alternative distribution service models with this particular program.

And we've been looking at in particular minimizing growth opportunities for these particular areas where it's gone in about optimizing energy efficiency and demand response opportunities.

We also have put in a lot of particularly renewable resources. Photovoltaics has been the primary resources that have been gone in these communities.

I'm not going to go into any great detail about energy efficiency programs or demand response programs only to mention that we do have third parties active in both of those programs.

We also do have third parties that are actually aggregating generators as well as loads as part of demand response programs.

As you are aware we did get a positive decision from CPUC on April 15th authorizing a 572 million dollar expenditure for RAMI. Part of that it was an all party settlement.

Part of what happened in that all party settlement and subsequently approved by the CPUC is the installation of remote disconnects and/or load limiting devices on all residential customers.

And we see from a distribution system operation perspective opportunities to use those technologies to better optimize how our system performs.

There was also a requirement for home area network which is yet to be defined. So we see that again as an opportunity to get into the customer via the meter to be able to provide them signals and information that will allow them to better control their loads.

And then lastly a couple of things. Greenfield development, we're actually currently working with a large development in our service territory where they are looking again at trying to expand the whole sort of sustainable communities program to encompass not just a building or two but the whole community that is going in. And it's on the order of 14,000 residential homes.

And so we are working with them to provide various alternatives standard electrical service that we would give them. And it's been going on for a while and we're very excited about the possibilities of doing some interesting things there.

And then lastly sort of on the R&D front in this area we have developed some microgrid proposals that we are moving forward with. Particularly we intend to file that with the DOE.

And that we are also involved in the state technologies advance collaborative, the EPRI demonstrating incentives for electricity providers to integrate DR.

A real quick discussion of San Diego Smart Grid Study. As I said we jointly funded this with the Utilities Consumer Action Network. John is going to talk a lot about this.

We provided all the as is data. And then John and the SEIC team went forward and then carried the work forward to develop the business cases.

From an SDG&E perspective we were looking to basically given all of the O&E modern grid efforts and all the telegrid concepts that are out there we wanted to look at really where are we relative to all these efforts and take a look and see where should be heading down, what path should we be heading down.

As I said we really view that the utilization of technology to address manpower system design and operations is going to be key to being successful in the future and providing highly reliable service to our customers.

And I think generally what we found is that conceptually we really agree with the direction that's laid out in that report.

From our perspective the only issues that we really have is the questioning of the business case reliability. We have been going through a whole pile of business cases lately and it really just gets down to the question of is it really a viable case in this point in time.

Now this time I'd like to change gears a little bit here. We've talked, Luther has talked about this, Russ has talked about this.

What we have done given some of our predictive reliability assessment tools and given where our SAIDI, SAIFI, MAIFI those you asked about industry wide standards reporting measures, those are them.

We're currently in the first quartile nationwide. We have a PBR in place. And every time we go for a rate case in the PBR the values of the targets for the PBR reliability measures gets ratcheted down.

And we began to wonder, well is that a good thing? Are we at a level where which maybe overall system reliabilities adequate but what about the actual individual customers?

We did some focus groups. You're going to see not only what is here, satisfaction decreases the number of outages and the duration of outages.

But what we did we contracted with KEMA. And we did some work with regards to focussing more attention on actual customers. And so what this graph really shows you is here, is this is the percentage of customers on our system. And this is the percentage of SAIDI.

And it's for the year 2004. But one of the things that we found which is very interesting was that 42 percent of our customers experienced 100 percent of the SAIDI minutes.

So for all the outages that an SDG&E service territory for 2004 only 42 percent of the customers were actually impacted by those. The rest had no impact whatsoever.

And if you actually take a little closer look at it what you find is that 10 percent of the customers experience 60 percent of the SAIDI minutes.

For us that was pretty illuminating because we're used to working on a system level used to trying to shore up the system, chasing after system reliability impacts. But what you see here is that individual customers particularly certain individual customers are really seeing a lot of the particular outages that occur.

And so we believe that we will improve our customer satisfaction by focussing and by putting our efforts on this. And so we have actually proposed a new reliability indices to both the IEEE Committees, Reliability Committees as well as we have proposed it in our general rate case to measure an alternative index.

And that basically looks at, it's called SAIDED and it looks like a reliability above the SAIDI values above a threshold. In our case we have picked a threshold of about 150 minutes.

So we would have PBR rewards and penalties tied to impacting clearly those 10 percent of customers and the additional ones as well.

And so to follow along on this, why are we looking at this? Why are we thinking about this?

This comes directly from one of the distribution automation reports that was recently developed for the CEC. And this just shows you the range of values service estimates.

And I believe this was in California. And you can see the large variability. And so the question that we asked ourselves is, as we move forward and we think about customer reliability, should there be differentiated levels of service or should each customer expect the same level of service. We haven't answered that question.

We also asked well what are customers willing to pay? Typically what we have seen is that while some of these numbers may fairly large, when it comes to actually going to a customer and saying, well I can give you widget X and that will improve your reliability 50 percent. Are you willing to, how much are you willing to pay for that? The answer is typically very small.

And an example of something like this is that BC Hydro is utilizing differentiated values of service for capital expenditure optimization as part of their asset management program. And it has been approved by their regulator in British Columbia.

So to conclude I think you've heard we as utilities and particularly at SDG&E really believe that the whole aging infrastructure requires a long-term continual investment. If we don't do that we're going to be chasing various problems and put out various fires.

But what that also requires is a broad-based,long-term support from all the stakeholders. Because absent that broad-based, long-term support we'll be forced to focus on some areas that will be to the detriment of the distribution system.

The other question really is we believe that the differentiated reliability levels of service require an additional investigation. We would really be good to get what level of reliability is enough or is there an enough?

We also believe that pilots of technology which are currently not cost effective require rate recovery. And we also think that given some of this market rate issues and this one is not on here but when we added and accelerated depreciation schedule for Smart Grid technologies.

As I pointed out one of the issues is that typically the book life of most of the assets of you would think of are on the order of 30 or 40 years.

We've got refresh rates of IT hardware of seven years. Clearly recovering those investments over that long period of time is clearly not appropriate but there's also sensors and other kinds of technologies that will be put in place and that will be continually renewed.

And we really believe that that does require some changes to some of the accounting rules.

And that we also believe that more R&D is required to address new technologies and address operational needs. We see that as a cornerstone of being able to provide reliable service to our customers.

And I would like to thank the Commissioners for their support of our filing, our GRC filing. And with that I'm open to questions.

ASSOCIATE MEMBER GEESMAN: Thanks Tom, that was quite interesting. I wonder if you would elaborate a little bit more on your concerns about the viability of the business case in the Smart Grid Study.

DR. BIALEK: Sure. If you look at -- And, you know, I'll let John speak to what's in there. The Smart Grid Study takes the DOE sort of modern grid vision and basically, you know, the business cases are out I believe 20 or 30 years.

And the real issue is, with some of the business cases we're doing now on technologies today to try to implement, what we're finding is that some of the technologies and solutions that are in the Smart Grid Study at this point in time aren't available or are very high cost. So some of the revalidation of business cases we have done is we have found costs have gone up, benefits have gone down.

The overall, from a societal perspective the business case looks really good. We're thinking about more from our internal stakeholder perspective where we have to justify to our shareholders a recover of our costs.

ASSOCIATE MEMBER GEESMAN: And my other question was whether you have quantified the workforce ramifications of a much greater automation of the distribution system?

DR. BIALEK: The answer to that is to a certain degree yes. As part of some of the business cases we are doing for some of our own internal initiatives we are looking at the costs and the benefits. And clearly what we see is if we do nothing part of the expectation is that we are going to have additional, require additional staff.

Let's take distribution system operations as an example. The amount of switching that we intend, we expect to do is going to increase significantly. However, without automation we currently have a manual process. So you can imagine what that means is that as that ramps up we need more people.

Well we expect that through automation of those systems through new technologies that we'll be able to levelize, increase productivity and basically keep the staffing levels as they are, or perhaps even decrease them in some areas and transfer people around.

ASSOCIATE MEMBER GEESMAN: And have any of those assessments been made publicly available?

DR. BIALEK: No.

ASSOCIATE MEMBER GEESMAN: Okay. Thanks very much.

PRESIDING MEMBER PFANNENSTIEL: Just to follow up on that question. So those haven't gone into a PUC --

DR. BIALEK: No.

PRESIDING MEMBER PFANNENSTIEL: -- GRC filing --

DR. BIALEK: No, they have not.

PRESIDING MEMBER PFANNENSTIEL: -- but they will, one assumes, for your next go around.

DR. BIALEK: Correct, yes.

PRESIDING MEMBER PFANNENSTIEL: This is

a blue card, I think it's for the next discussion, though. I think it's the 11 o'clock panel discussion.

MS. KELLY: Okay, fine. Anybody on the telephone have a question? Hearing none --

PRESIDING MEMBER PFANNENSTIEL: Let me just make sure. This is from --

MS. KELLY: Sorry, Nora Sheriff.

PRESIDING MEMBER PFANNENSTIEL: Did you want to speak to this panel? Do you have questions for this panel?

MS. SHERIFF: No, for the 11 a.m.

PRESIDING MEMBER PFANNENSTIEL: Okay, that's what I thought, thank you.

MS. KELLY: Thank you. I'm finally getting this and the lights.

Our next speaker is John Westerman. Mr. Westerman is a senior program manager in SAIC's energy consultant practice. He has more than 18 years experience in the development, evaluation, application and testing of energy technologies.

Over the last two years he was chairman of the San Diego Regional Chamber of Commerce Energy Committee and he is one of the coauthors of the San Diego Smart Grid, Mr. Westerman.

MR. WESTERMAN: Thank you very much. This study was funded by SDG&E and UCAN. And the objective of the study was to answer the fundamental question is does it make sense for the San Diego region and the utility in that region to pursue a Smart Grid. And what the benefits would be.

This study was intended to be a very first look at answering this question. A lot of the things are very conceptual and but the question was does it make sense and to develop a roadmap to get there and identify a method of implementing a Smart Grid.

So I'm going to go to the end of the story first so we can see what the answers are. And then I'll tell you how we got there.

The study identified a portfolio of technologies to be implemented that showed a significant savings by implementing the Smart Grid technologies.

The results had annual of about 141 million dollars per year. And over a 20 year life we quantified the system benefits and the societal benefits.

And part of the philosophy of the study was to look at if a Smart Grid is implemented it's not only for the benefit aren't only for the utility but they're for the region as a whole in terms of better reliability, job development, fostering high tech industry in the region.

And so we felt that the societal benefits were very important because there are secondary benefits that are outside of the utility that are realized through the system.

The estimated capital costs was 490 million dollars and the estimate of about 24 million dollars for O&M of the grid over and above what would typically be expended because of the Smart Grid technologies.

So the conclusion of the study was that the benefits can be achieved and that a Smart Grid does make sense for the San Diego region.

Our methodology of how we got here the premise of the Smart Grid is from the Modern Grid Initiative. We decided that we're going to take the initiatives from the DOE Modern Grid Initiative and apply those to the region.

And we started with what the objectives are in the San Diego region and SDG&E and did a study of the as is status of what's in the region and what's planned. So we said, here's the status quo and here's what's being anticipated to happen and then brought all of those together to look at development of scenarios as to whether the Smart Grid makes sense.

And from that, from the scenario analysis we did a Gap analysis from, here's what we have and here's where we want to be and developed a portfolio of technologies and a roadmap for implementing them. And then did a cost-benefit analysis as to what the economics looked like. And then made recommendations as to what would have to happen in order to bridge the gap and to start developing this Smart Grid.

So the major findings we had for in the current status of San Diego is that as Tom displayed in his presentation there is a growing population of DG both gas-fired and PV in the region.

One of the things we're look at as a Smart Grid is you look at what's at the end of the distribution and look at resources as far as what the customer is doing, what they need and how they're impacted along with out of region generation and how you get the electricity from where it's generated to the end points.

We also identified that the existing communication infrastructure that the utility has isn't sufficient to support the amount of communication that's required in a Smart Grid. Because when we're talking about a high deployment of sensors, communication between devices and there will be a significant investment requirement for the communication.

One of the fundamental things that helps support some of these things is that we took into account the AMI project and that's an assumed to be going to be implemented in our study. So that is one of the building blocks that is you don't see it the study as something that is funded through the study because it was already projected that it was going to go in.

And in doing the analysis we had to look at the filing, the AMI filing to identify those benefits that SDG&E was already projecting through the AMI project to make sure that we weren't double counting the benefits from the technologies that we were planning on implementing through our study.

SDG&E also has some substation automation programs in progress. Some field SCADA switch roll out programs and the BPL demonstration project.

One of the other things that we felt in the study that really helped facilitate the benefits of a Smart Grid is the California Loading Order.

Because by utilizing energy efficiency, renewable power and demand response those things really help facilitate, they're another tool in optimizing the operation of the grid.

So I'm going to go back and forth a little bit here. Under our scenario analysis we identified three areas of impact looking at economics in the region, environmental regulation in the region and then technology development.

And under each of those categories we looked at the extremes for the economic development from a blue sky everything is hunky-dory and everybody is happy to recession where businesses are leaving town.

And we did an analysis to identify those drivers that impact the grid under each of these scenarios.

And when we did that we had a focus group of people working on quantifying on a scale of zero to ten whether the extremes in each of those areas would make a case for a Smart Grid when we're trying to answer our question, you know, does it make sense for the region to pursue a Smart Grid.

So we see that the blue sky and the breakthrough technology are right on the fringe of being able to substantiate a case for a Smart Grid. Where the high level of environmental regulation is not, doesn't make a strong case for or it doesn't, it's in the middle. So you would have to have other reasons to justify going forward with a Smart Grid based on if you're in this region.

And then the last three were found to have not to make a strong case or not a case at all for moving forward with the Smart Grid.

And so when we go back to what we forecast for the San Diego region we forecasted continued economic growth, high level of environmental regulation and anticipation of fairly rapid technology development.

And we saw trends in regulation that

would increase the, further increase the installation of renewable energy, the use of alternate fuels as well as higher levels of energy efficiency and demand response.

The other thing with San Diego, we looked at the business climate in San Diego. San Diego doesn't have large industry. A large number of industrial customers. Most of them are smaller, they're large commercial customers but they're not real energy intensive. There's not oil refineries. There's no car manufacturing. It's mostly the profile follows more of an office building type of application.

But there's a lot of high tech businesses in San Diego that require high levels of power quality, high levels of reliability especially in the biotech sector where they have experiments going on that if they get out of their control conditions which could be caused by power irregularities that there's a significant cost in their development processes that are sacrificed.

So when we got to the Gap analysis we looked at the, we're looking at these as a pyramid of how you build the grid and implement the things.

And theses here are directly from the Modern Grid Initiative called the Key Technology Areas. And so this represents where we want to be. This represents where we are right now.

And you can see that we have sensing and control devices. And here we have sensing, metering and measurement. And on the Smart Grid the number of sensors, the number of measurements and metering is a lot higher than the current state.

And so when we are looking at building the portfolio for a Smart Grid we're looking at building the base, installing these grid components that allow you the flexibility to do various things on the grid. And once those are installed then we're adding the sensing, metering and measurement and then the communications and the control methodologies on top of that and finally with all the sensors being read and all the control algorithms on we're adding some decision support and human interface components on top of the pyramid in order to visualize control and to make sure everything is integrated in an optimal manner.

So this is a list of the attributes of a

Smart Grid. Basically we're looking at the ability to detect and address emerging problems before they impact service, make protective relaying the last line of defense and not the only line of defense.

Respond to local and system-wide inputs. Incorporate extensive measurements and rapid communications. Automatically adapt protective systems to accommodate changing conditions. Re-routing of power flows and changing of loads. Improvement of voltage profiles and the ability to take corrective steps in a matter of seconds.

Again we're looking at enabling the load to distributed resources out at the end of where the customers are located.

We're looking at improving reliability and security. And then again the top of the pyramid with the system operators advanced visualization tools that help provide the human oversight that's required for the operation.

When we did our Gap analysis we identified 26 what we called improvement initiatives to be implemented as a Smart Grid.

And out of the 26 we narrowed it down to these 13 that our project team identified as what we thought was the best approach for implementing the Smart Grid.

And you can see that we have a group that is three areas of communication because we were looking at Ethernet over Fiber is addressing the long-haul communication. The 4G WiMAX is looking like at mid-haul communication. And then the Zigbee/WiFi - Wireless is the short haul.

And this is where we're looking at the ability to have the device inside the AMI meter to be able to reach into the home or the customer's business to control end use devices.

And we think that the integration of a number of these technologies was a better approach than having just one communication approach for the program.

The other thing is that it's obvious from this that we came up with 26 initiatives is that there's not one silver bullet that's being identified that's going to solve all the problems on the grid.

It's going to be a portfolio approach and it all has to be integrated in a smart fashion so that we have a network system that's adaptable and high performing.

So we looked at in our business case where the benefits come from implementing those technologies. And the list is here and the top four that were identified where most of the savings came from were the highest one the reduction in forced outages.

The second one was an increase in job creation. Again this is a societal benefit. But when you look at the potential for technology development the number of people it's going to take to implement the system and operate once it's going there's a significant job creation growth through this program.

The third is reduction in peak load. And this is not a demand response reduction. It's a an increased efficiency reduction.

And then the fourth one was the reduction in congestion costs. Now in our study the reduction in congestion costs we were looking at significantly reducing the current RMR costs but those expire after a number of years.

And so the value in reduction of congestions costs are higher in the near term than they are out years.

Once we identified the portfolio and we

had the costs and we had the benefits associated with them the next thing we did was to look at how you would phase in that portfolio of improvement initiatives and what approach you would take.

We came up with three scenarios. One is the earliest positive cash flow. And in this scenario we looked at starting at the bottom of the pyramid and building things in phases and trying to get the highest return or positive cash flow from the early investments so that we could use the savings to pay for future investments.

The second one is maximum benefits early. And this is basically putting, installing the infrastructure that gives us the biggest bang for the buck as soon as possible so that the benefits start accruing the fastest.

And then for each of these scenarios you can see that the internal rate of return and the NPV will vary. And for the optimized IRR case we were sliding the phasing of the improvement initiatives around until we found an optimized level of between NPV and the IRR.

But you remember we have a lot of footnotes here as to what we're talking about as far what the IRR means and that these numbers vary significantly from what SDG&E would realize if they had to fund these under the current rules of engagement for recouping their investments and getting them approved through the CPUC process. So this is the San Diego region benefits in economics.

So our roadmap for how do we get there, we started with, we're going to move very quickly. We wanted to make sure in the study is that we're not looking to say 20 years from now we to start doing something. We're saying that integrating the Smart Grid technologies there's a lot of things out there that can be done right now. That we don't have to wait for a technology to be developed.

Obviously there are some here that are in the early stages of development that we're anticipating are going to be included. But this is actually an aggressive implementation roll out plan where the first phase is used to establish the foundation for the Smart Grid and then start creating the benefits through improved reliability.

This scenario here that's shown on this slide represents the middle scenario on the last slide which was the maximum benefits early.

And then the second phase, you can see the second phase falls, the dates fall within a subset of the last phase because these are a roll out over the years. And then as we get enough infrastructure after the first couple of years of implementation we can start adding things that we can integrate the consumer systems into the Smart Grid. And then also start providing economic electricity services to further maximize the functionality and the benefits of the system.

The next thing that we have is a conceptual idea of some the Smart Grid implementation. So we have the basic what we have now, the substations, the loads at each end.

In the phase one we start adding sensors. The AMI is assumed to be interfaced to the customers, start putting in DG at strategic customers, communication systems and the sensor network are installed. We're looking at implementation of some energy storage devices and then some of our control at needed areas.

And then in the second phase we start bringing in utility owned DG systems, some intelligent agents for control and optimization of the system.

And ultimately we're showing on this grid the conceptual outline of what a microgrid would like with the utility owned DG and the sensors in operation and the energy storage.

Again we're looking at another roll out slide kind of reiterates on a case by case basis what we're looking at. We have a number of initiatives that we added. We have asterisks by that have been moved out to accommodate some time for them to be developed or the cost to come down or to be proven through some R&D programs.

The four R&D areas that we identified in the study. We recommended doing a WiMAX pilot for the mid-haul communications. A pilot with an advanced energy storage device. And then also looking for a microgrid demonstration project. And then development and testing of these agent software systems that provide some autonomous and smart control systems.

Some recommended policy changes that came out of this study. In order for the Smart Grid to be optimized and take full advantage of it we're recommending that we need clear and low cost market signals so that customers can make decisions as to when they want to use electricity and have some incentives for when the cost of utility a lot for the services that the customers have information to be able to make decisions on how to use that.

And in a Smart Grid ultimately the customer doesn't have to make a decision in looking at it right there. He has a system already configured and programmed so that when the signal is sent to him he's already decided which things are going to operate or not.

We're recommending incentives for the use of advanced technologies that increase capacity or improve efficiency. CEC supported evaluation of economic benefits of commercially available voltage stabilization technologies.

Everybody has discussed this so far so the open architecture, interoperability, reliability standards are required. And then also new rate designs.

And this is specifically looking at residential customer rates to because right now it's difficult to get the residential customers engaged in doing very much with their load with the current rate structures.

And then finally in keeping with our philosophy some way for the utility to take into account some of the societal benefits when they're looking at implementing some of these technologies.

And the report can be found at this website here, on EPIC's website if anybody is interested in downloading it and going through all the fun reading there.

ASSOCIATE MEMBER GEESMAN: John thanks very much and I certainly enjoyed reading the report when it came out. What's the follow up strategy?

MR. WESTERMAN: The follow up is that the ball is in SDG&E's court. The date and my understanding is that they are pursuing several of the R&D programs. There are some other things that I know they're working on but I'm not sure that I can discuss those. But SDG&E is being very proactive and they're taking a hard look at it.

They've gone back and looked at our numbers as far as the mostly from the business case I think that the technologies and the portfolio approach. You know Tom has said that they conceptually agreed with that.

The next step is given our assumptions in the report and that it makes sense, the things need to be looked at a lot closer. We looked at the number of substations and assumed constraints on so many of them by a certain percentage. We didn't go out and measure them and quantify them.

So the next step is to do a more detailed analysis as far as what parts of the infrastructure can be addressed to get the biggest benefits as soon as possible and to get better costs numbers and to basically do a more detailed analysis and to demonstrate some of the benefits through some of these R&D programs.

ASSOCIATE MEMBER GEESMAN: And I believe you said that you were involved in the San Diego Chamber. How did they respond to the report?

MR. WESTERMAN: Very favorably. The Energy Committee for the Chamber of Commerce in San Diego is very active. SDG&E is very active in it. It's a community of people who are very knowledgeable in the area of energy and are very forward thinking.

And most people see that it's not a far stretch of the imagination to think that that resource of the distribution and transmission and use of electricity is more intelligence needs to be and optimization needs to be applied to it.

ASSOCIATE MEMBER GEESMAN: You know just to give my perspective on how the process works. Bridging that gap between societal benefit and company interests or benefit on the part of the utility is a challenge. But San Diego, pretty compact service territory and extremely well organized local community, more people and more interests or more entities with interests in energy than I think we see anywhere else in the state. It's really within your capacity to agree as a community that you want to do this.

And I'm being loose with what I described as this. But I do think it's within the local community's hands to determine if this is the right way to go.

I acknowledge having known them for a long time UCAN can sometimes be a little slippery on that but I think that they've at least indicated an early interest in commitment.

If you're able to arrive at that type of general consensus I think the regulatory system will respond pretty quickly and pretty effectively. That's the premise that we've used in so many of our other initiatives over the last several years, the Solar Initiative, the Greenhouse Gas Initiative, our emphasis in the loading order and efficiency trying to capture societal benefits and somehow reconcile that with the utilities' perspective.

So I strongly encourage it and if there's anything that state government can do to facilitate that process I don't think you should be hesitant about asking us to do that at all.

MR. WESTERMAN: I'm glad to hear that. I think that in my experience in San Diego we always think that we're the little guys at the end of the cul de sac and it's hard to get our voice heard up here a lot is our perception. So I'm glad to hear that.

ASSOCIATE MEMBER GEESMAN: There's more strength at the end of the cul de sac if you can get all the neighbors to agree on a general direction.

MR. WESTERMAN: Right.

ASSOCIATE MEMBER GEESMAN: And I think you realize that.

MR. WESTERMAN: And just as a follow up to that in San Diego the organization through the

SANDAG group is developing a lot of momentum in that area as well for many energy related aspects for our community.

PRESIDING MEMBER PFANNENSTIEL: I have two pretty specific questions on some of these assumptions that you gave.

One has to do with the question about rate design as important to give customers the right incentives. Have you started, have you gone to the PUC or has SDG&E gone to the PUC with that recommendation because I, it looks like it's fairly fundamental and I may be wrong but that's how I saw it.

MR. WESTERMAN: As far as I know it's only been identified but no active steps have been taken. Some of the things that we envision in a Smart Grid is for instance like power quality, some customers would be willing to pay for power quality but there's not a rate for your high power quality customer and we can charge you more to insure you have your requirement.

That would be a rate design that would be in there. And then also for a number of aspects there's not a rate design for capacity, value of capacity for several technologies so those are some of the --

PRESIDING MEMBER PFANNENSTIEL: In your cross benefit analysis did you assume that there would be those kinds of rate designs or was that not necessary.

MR. WESTERMAN: No there was some assumptions and the biggest assumption on rate design was basically addressing the residential customers. And then also for the value of electricity on the market that could be sold from distributed generation into the grid.

PRESIDING MEMBER PFANNENSTIEL: One other question on your assumptions, you showed an increase employment in the benefits in the region. And yet at some level it seems like that may be a net question because with more automation one assumes that SDG&E would use fewer employees on their distribution and maintenance concurrently. So I can see where one would be a higher skill level.

But is it in fact net, net warrant more people?

MR. WESTERMAN: Yeah, we were looking at not only at the people for implementing and operating the grid but we were looking in being, probably being optimistic that if the San Diego region had a Smart Grid and could demonstrate high reliability, high power quality and the benefits that specifically high tech type companies would want to use that you would draw more businesses into the region. Because we'd be such a great place to live.

PRESIDING MEMBER PFANNENSTIEL: I see. You are very optimistic, thank you.

MR. WESTERMAN: Thank you very much.

MS. KELLY: There's no questions on the WebEx. Telephone participants, do you have any questions?

UNIDENTIFIED PHONE SPEAKER: No.

MS. KELLY: Thank you.

PRESIDING MEMBER PFANNENSTIEL: I see one question here. You need to go to the microphone in order to have that question heard by people on the web.

MR. RACHLIN: Sure, thank you. Hi my name is Aaron Rachlin from Borderland Wind in Los Angeles. And John in your presentation you mentioned in the recommended RD&D projects, advance energy storage. I was wondering if you could just give a little bit more detail on the nature of that.

MR. WESTERMAN: On that one we're looking specifically at electricity storage and we were looking at battery technologies, flywheel technologies. There's a couple more but there in the portfolio of the Modern Grid. There's a whole group of energy technologies that are in that bucket that are being looked at.

And we feel that at some point one of those is going to emerge as a viable technology to be implemented into the system.

MS. KELLY: Thank you. The next part of our agenda is a panel discussion. And what I'm going to do is that I have a number of questions that I have posted in the agenda. I'll join the panel members there. We'll read off a number of those questions and then what I'd like to do I think because they do ask about utility investment if we could start maybe at the bottom of the cul de sac now and have Tom and just go, Luther and Russ respond and then John Westerman and Eric Lightner I've asked to join us in this discussion because he brings a perspective from DOE. And the whole modern grid concept started with DOE.

So I feel like Eric's organization is

the father of this activity or the mother. So I'm just going to join them at the table. And then I will start with the first question and this is meant to have an interactive summary type discussion.

Each of these presentations has suggested we want to do this, we'd like to do that. I'd like to just focus in on what some of the priorities are. What they're doing now and what we're looking for in the future.

Okay, the first question, California utilities are investing at record levels in new and old distribution systems. Russ I think gave us an idea of the numbers are in the billions. And this is a substantial investment that will be with us for quite a while.

And so most of this material as I think actually Luther said has long life, at least 10, 15, 20 and 30 years. So I think it's very important to begin discussion about what we're doing today and how it's going to serve us in the future so we can plan for that future in advance.

So the first question I had and I'm going to put the first two goals together to Tom. What components and designs are being used and will the distribution systems built today support the environmental and sustainable energy goals that California has established.

In particular I'm thinking of the renewable portfolios standards, CHP integration, demand response and now more recently CO_2 reductions.

DR. BIALEK: One of the things, one of the things that maybe I didn't mention when we talked about the Smart Grid, conceptually like I said we, SDG&E agree that that's probably the path we're headed down. You've been headed down that path anyway.

So when you say what components and designs are being used, I mean traditionally we know what a transformer looks like. We know what a cable looks like. We know all these bits and pieces of equipment, the manufacturers are out there developing new technologies. We are looking to try to incorporate those new technologies and designs into our systems.

In a meeting we had the other day one of the things that we talked about was just a whole rejuvenation of the systems and implementation of new systems in place to try to achieve as I said it earlier the high level service reliability to our customers with a maturing workforce, different skill sets.

And so I would say that we're doing the best we can with technology that exists today because first off if you look at what the technologies that are out there that people are offering you'll see there are variance on what we have today. Some have some more advanced features.

One of the difficulties we face with some of that is as the manufacturers are developing products what they are doing is basically obsoleting their earlier generation of technologies and so for one particular vendor we have six different versions of a controller and none of them are backward compatible.

So you get into those kinds of issues. But I would say that in general we are taking a look out there. We have given this study, given our participation in the DOE Modern Grid Initiative we believe we're looking forward and trying to implements systems in place that will try to get at supporting the state policy goals. And that's really where we're headed.

And I see that as time goes on that we will able to do things with these systems in place like AMI and a lot of the automation that weren't envisioned ten years ago. But we did start putting them in place.

And so it's not a total, it's starting to, our system is starting to morph from a 1950s vintage into a much higher technology kind of environment. And we just see that continuing.

MR. DOW: I'm like Tom. I think the design of the technologies are being made by the manufacturers and we're utilizing those. Where I see us doing some of a lot of work is in the area of how do we design our system differently using our current technologies.

Or what new technologies do we need so we can encourage and support the, for example, solar homes. What does a subdivision lay out look like for a hundred percent penetration of solar in a new home.

We don't know what it is. We don't know what how all those are going to interact. And so we're redesigning our systems on how we think it's going to be. And so we're going to have to do a lot of careful monitoring of that to make sure that that's, that we provide the service that we need to provide.

I think we are doing what we have. I'm not sure everybody knows what it's going to look like yet. So we have to stay with it.

ASSOCIATE MEMBER GEESMAN: Do you think that there is a market demand out there for differentiated level of service at the distribution level?

MR. DOW: Is there a demand, I think it is probably at the commercial level perhaps. But I'm not sure at the residential level.

ASSOCIATE MEMBER GEESMAN: But you'd say that in today's commercial class you can see the logic of some customer stratification in terms of quality of service?

MR. DOW: Yes sir.

PRESIDING MEMBER PFANNENSTIEL: Isn't it the case where say high tech companies were willing or are willing and actually are paying more for high levels of service?

MR. DOW: In some cases they are. They are doing it generally through back up feeds and UPSes.

PRESIDING MEMBER PFANNENSTIEL: Oh, so

it's not a specific rate design there. But it is a fee based.

MR. DOW: Yes, they're looking for a company, we're trying to work with them on excess capacities that they can buy as excess capacity so that they can have a back up.

MR. NEAL: When I look at what we're doing in the area of developing the grid to meet these goals I see a couple of things.

One, there's are a lot of little incremental improvements. The basic design is still a substation breaker and a radial feed going on out using wires. So it's not dramatically different.

But there are continuing incremental improvement in the equipment being used. We mentioned how we're going to upgrade the types of cable, some places where in the past you'd have manually operated switches that were oil filled boxes sitting in underground structures are now going to be perhaps gas insulated but have a vacuum breaker type technology inside which represents and incremental improvement of what you have out there.

I would say that the most significant

thing that's going on right now that will assist in our environmental and sustainable energy goals is AMI. Because AMI represents the drafting of customer loads into the system scheme.

The fact that we'll be able to have a much more ubiquitous communication system out there throughout the distribution system and the ability to reach into customer homes and facilities and perhaps cycle or turn off or modify the behavior of loads during for instance for things like peak shaving, for taking credit for rolling standby energy sources, and even for being able to have that customer load respond to modulate system upsets where you'd be able to say well now we don't, you may be able to, given that you have the ability to make a proportional response, a smooth response of customer load to a system upset you might be able to stabilize some of these upsets without anybody even knowing that you're doing it, without having to build additional transmission lines and so forth to meet these transient contingencies and things of that nature.

So I think that the AMI system is the most encouraging thing that I see there. As far as some of the other, you know one thing that I'm observing is that in attempting to meet our renewable portfolio standards and some of these other things there actually coming into realization as concentrated remote generating plants, wind farms, geothermal facilities, places out in the desert where you have acres and acres of solar sterling engines or something like this with a massive transmission upgrades to actually bring those things in.

It's not really impacting the distribution system. Or the distribution system is not contributing that much. I'm not afraid of a million solar roofs putting a strain on the distribution system in any way. That will just appear as a modulation to our local load growth and will be accommodated by our normal ways of dealing with that.

But given that you have, if you wanted to do more in the area of distributed generation that was, let's say CHP-type things which were and going to be able to use those as a system resources, probably the fact that you'll have a more low-cost, ubiquitous communication system as a side benefit of AMI might make integrating these distributed generators into some kind of control scheme and take you know, a lot of time people talk about the benefits that they have in the distribution system, but a lot of those benefits are hypothetical if you don't really have any communication and control and means of integrating it into your planning.

If we get the AMI out there as we are currently envisioning it that situation might change.

MS. KELLY: Russ, can you put your microphone on.

MR. NEAL: Oh, should I turn it on?

MS. KELLY: Yes, please. He said he was hearing you so I didn't interrupt you. Thank you.

ASSOCIATE MEMBER GEESMAN: Russ the San Diego Smart Grid Study spoke of utility-owned distributed generation in one of its phases. Is that something that Edison would consider?

MR. NEAL: Yes we would consider that. There's a couple of things that impact us there as we've thought about that. I mean it's illegal for us to do it today.

When we do a, when we do our annual evaluation of DG as a substitute for a distribution wires investment, we've never found a case where distributed generation whether we owned it or somebody else would be a cheaper way of meeting the distribution, the cost per kilowatt there and there is an order of magnitude or two orders of magnitude difference in many cases between those.

But what is the most attractive thing would be if you have, when you have some of the customers who have a particularly attractive combined heat and power application, let's say a hotel or a hospital with a heavy laundry load and things of that nature, schools with swimming pools, things of that nature, the complicating factor becomes that there may be an energy benefit of going with CHP there but the owner doesn't want to get into the energy business of managing, they would just as soon just have a hot water heater going someplace and pay the bill as they would have a rotating machine with emission controls and electrical issues and all that sort of thing that's a headache for the owner.

So some third party entities that tried to get into the business of being the, of running and operating those things for the third party and interfacing with the utility, I think if the utility was able to move in and be a generic energy provider, provide both the heat and the power which Edison in particular is not in the gas business so we have not attempted to move into having any kind of a rate where we can sell Btu's of heat to somebody's swimming pool and that we would then maybe own a CHP plant on the customer's premises and so forth and so on.

But the idea has been kicked around. And I think it has certain advantages in that you have fewer parties that have to all get lined up to make something happen if the utility was able to do, to say, look we'll provide you your heat, we'll provide you your electricity, we have established rates and we'll just do it whatever way makes sense in this application whether it's with CHP or something else. You know that is potentially attractive.

ASSOCIATE MEMBER GEESMAN: I think as you get younger and more entrepreneurial types upstairs in the executive suites that might be perceived as an attractive business opportunity for you. And one that you might find a lot of receptivity among regulators for.

MS. KELLY: John you're just there and then we'll come back to Eric.

MR. WESTERMAN: Yeah I think that one thing came to mind. I think that the AMI is obviously the great foundation for taking where we are now and moving forward.

And it's also taking the utility from transmission and distribution lines to being a huge IT organization because there's a lot of data and a lot of data management to go into that.

And the other thing is that I think the, with SDG&E going into incorporating the disconnect capability on the meter that was proved that going back to the energy crises days which I we won't again, but it allows them to have the ability to disconnect at the customer level and not at the feeder level. So there's an opportunity to control that better. So it's a less disruptive solution to the same problem.

MS. KELLY: I think I'll just go through the questions and then see if anybody has additional comments on that. Would that work in the interest of time?

The next question, Eric has already indicated he has nothing to add to that first question but wanted to add to the second. So I will go over the second question and start with Eric and then we can just move around the table.

What are the most significant barriers to creating a modern 21st century low carbon energy network? And to me, I'm going to talk about that in my own presentation. But a low carbon energy network is where a customer, low carbon resources, are integrated fully with the utility system.

So what are the most significant barriers to creating this modern system? And we have had some comments on AMI. How will AMI contribute to achieving these objectives? Eric.

MR. LIGHTNER: Okay.

MS. KELLY: Please give your name when you go around.

MR. LIGHTNER: I'm Eric Lightner from the Department of Energy.

And I couldn't answer that first question, Linda, because I'm not out there implementing anything. I'm just sitting in Washington DC just like you are sitting here. So I figured I wasn't qualified to answer that first question.

But the second question, and I'll expand it a little bit. What are the most significant barriers to creating, you know, more of a modern grid, modernizing the 21st century grid. Not just for the carbon energy network, which is your objective here but, you know, I really think it comes down to not necessarily a technological question. I think it comes down to having the political will to make it happen.

And really, you know, raising the issues like we're doing here today, like we did two weeks ago in an event that we had in DC called GridWeek and events like this to really raise the issues, talk about them in public forums. Engage decision-makers at a very high level that these are the issues, these are problems. These are the benefits if we can reach those goals that we have. So I really think it's a matter of raising the awareness to the people back that can make the decisions to make the changes happen.

Now that being said I think on the technological side there is one major issue that stands out in my mind that I have heard over the past two years, that I have heard here today, that I have heard again at the GridWeek event. And that's really this whole issue of open protocols, communication protocols and interoperability, to enable interoperability.

How can we get devices across the enterprise and between enterprises to really be able to exchange information so that we can act on this information in a much more effective and optimized fashion.

Really that's what I've seen. If we can crack that nut, if we can solve the whole interoperability issue I think we'll be able to really see and realize a lot of these benefits that we all believe are just there waiting to be tapped into.

DR. BIALEK: Tom Bialek. I would concur with a lot of what Eric has said. But in particular now from more of a utility perspective.

I think one of the big things that we see as we go forward is the individual operator or utility employee with we sort of call it information overload. That we see as something that's going to need systems, going to need a whole pile of things in place just to deal with all the AMI information, the sophistication with regards to automation of the system. Again, these aren't in any particular order but, you know, those are some of the issues.

We also see that, I would say that one of the biggest things is cost. If you say to us today, how much -- As I said, for us to turn over the entire system it's a huge, it's an astronomical cost. And then not just of the existing, replacing the existing stuff in kind but even some of the newer technologies that are coming out. They're on the borderline of being really commercially available, being commercially viable and so they're also at a very high cost.

Another thing I'd point out I think is sort of also the customer acceptance/ participation. We have, I think to address your question with regards to rate design, in our GRC phase two we do have rate design issues with regards to critical peak pricing rates for customers. So that is in there.

But it's just for their level of sophistication. Today people when we talk to particularly residential customers, the expectation is, I flip the switch, the lights come on. I plug something in the outlet, it turns on whatever. You know, my computer goes, all those other kinds of things. They don't necessarily understand their impact.

And even if you gave them a pricing signal they'd be saying, well what do I do with it. They're not sophisticated enough at this point in time, and certainly part of the AMI roll out, the customer education piece I think is going to be something that is going to be really important as things move forward.

I think you see the commercial and industrial customers being significantly more sophisticated and ready and willing to embrace the kinds of new technologies that are out there.

Also some of the technologies that are sort of envisioned to a large degree are, as I said are, while they are available they're available as onesies and twosies or they're, you know. So there's really a whole level of R&D even on technologies that don't even exist, that are envisioned as to providing solutions.

And then with regards to one of the big challenges I think is going to be for clearly photovoltaics and wind. It's just the whole issue with regards to, as you incorporate them, the dispatchability issues associated with them.

They're going to be there when they're going to be there. And you're going to have to sit there and look at your system, look at your other generation, move that around. Start adjusting other switches, devices on the distribution system to accommodate them, and that's a totally different model than what we have today.

But for us, yes, clearly AMI will be there. We see it providing important audit restoration information as far as where it is. Also helping that restoration process because we now can get our trouble men and our crews to the locations faster.

We also see something from our side which is right now for single load lights. So in other words a customer's breaker on their panel has blown. Right now we send a trouble man out to the household to take care of those problems to ensure that indeed they have power to their system. Well we envision that with AMI that we will have that information readily available and can tell them.

We also see that it provides opportunity to identify issues with regards to how the system is operating and what it's state is. And that comes down to local loading. What can I push harder. Optimizing utilization of assets. And just better levels of information for our overall system, system design and optimization.

And just looking at given, we give you a price signal. What would that response be and how does that change how we plan and a design system. So those are a few things.

MR. DOW: Luther Dow. Very similar comments. Maybe saying it in a slightly different way but I think similar to the same themes.

First of all I'm not sure whether there's a full agreement on how the system works. What is the system? We have a vision of what it might look like but we're not sure how it works. Are we going to -- Is the utility going to control the load or are we going to provide price signals to the customer so they can control the load?

Those are two different approaches, they end up with two different -- you end up with two different solutions depending on how that works. So I think there's still a lot of understanding that needs to take place there.

I wrote down interactivity between the

utility and the customer. How do we make full use of these low carbon resources when they're available? So there needs to be, there needs to be some interconnectivity or interaction between the utility and the customer. I call it a partnership and that's what I think the future looks like is a partnership between the utility and customer.

I'm sure the system is going to have to be modeled differently when we have all of these devices on the distribution system and we don't have those modeled in there today. So we're going to ultimately have to do that, look at it differently.

And the one thing that we're really looking for and trying to make sure that we have is we need to have early successes. We need to have -- The first prototypes and the first projects need to be successes so that we don't, so that we don't fall backwards and we can build on those successes as we go forward.

And then the last piece, of course, is the cost of doing this.

And I agree with what has been said about AMI. My comment about how will it be used and it's going to provide better support to the customer. It's going to really be useful to the customer. And also useful to the distribution system in the fact that we'll be able to monitor loads better, we'll be able to respond better and we'll be able to do load management better and the system will run more cost effectively.

ASSOCIATE MEMBER GEESMAN: Do you think that the roll out of AMI will facilitate a greater ability on the part of regulators to bring rates and costs into closer alignment? Particularly time of use costs.

MR. DOW: Yes.

ASSOCIATE MEMBER GEESMAN: What is going to happen when my neighbors in a pretty low air conditioning area discover how much we are subsidizing, cross-subsidizing new air conditioning in the Central Valley? And I suggest to you that each of your service territories are likely to find the same geographical discovery on the part of coastal residents.

Won't AMI potentially be one of the most disruptive technologies ever introduced onto your system? I think there's very clearly that potential because we have allowed our rates and costs to fall so totally out of alignment with each other.

And don't get me wrong, we're strongly supportive of AMI at this Commission. But I think we are also just as supportive of trying to limit cross-subsidies and align costs with rates.

MS. KELLY: Russ.

MR. NEAL: Well, this is Russ Neal with Southern California Edison. The opinions are my own here, not those of my employer necessarily.

But as I just read the words here and it says, what is the most significant barrier to creating a modern 21st century low carbon energy network. I mean, my honest answer to that would be the state's current aversion to considering nuclear as an option.

What got me thinking along these lines, in order to shift a little blame here, it was some of the work that came out of Eric's shop in DOE recently about the use of plug-in hybrid electric vehicles as a load leveler for the system. One of the salient features of our electric system is the load factor. The fact that we have this enormous capital infrastructure which gets very low utilization sometime and is strained right at the peak at the other time is one of the most uneconomic features of our current electric system.

And when one considers Eric's study, the DOE report that came out and said how plug-in hybrid electric vehicles could be integrated with the system through the AMI which allows now, that would allow this communication now for optimal charging, and in fact even using the battery storage of the vehicles as a resource for the grid as well as the grid a resource for the vehicles, is a very, very attractive avenue to explore.

And if then the baseload, if then you're moving all of your generation into almost a baseload mode the case for either things like nuclear or a coal system with carbon sequestration that is providing an economic baseload, low emission situation. And you're also moving a lot of the vehicle emissions out of the picture at that point. Is to me an extremely scenario that is not getting the consideration its due.

MS. KELLY: Let me just --

ASSOCIATE MEMBER GEESMAN: I think it's getting more consideration than you might think, Russ.

MS. KELLY: Just let me add one thing. When I gave Russ's references I did leave out this one part because I didn't think they were relevant. He's a registered professional in both electrical and nuclear engineering and his previous experience includes five years as an officer in the Surface Nuclear Navy. So now relevant to your comments.

We need to keep going but do you have one last comment, John?

MR. WESTERMAN: Yes, there's a couple of things. One is, one of the things talking about the new technologies. I think that one of the premises of the Smart Grid is that it's not fully dependant on the development of new technologies.

It's dependant on changing the way things are operated and how data is collected and how things are controlled. So if there was no new technology development, the new technology helps facilitate it but it is not required to start going down that path.

And the other thing is I think there's a, it's not a barrier but I think there's a missed opportunity because I don't think that there's a -- I'm one of the only non-utility people sitting here so don't take it in a negative manner.

But I think customers are out there doing things to try to improve their businesses and reduce their energy costs. And the utilities have programs to do similar things for the customers but they're not, there is not a partnership. There is not really a partnership and I don't think there is really a mechanism at this point for the utility to go out and be able to say, we'll help you solve your problem and in the meantime with the resources that get implemented we can help you as a resource for solving some of our problems.

And I think there is a large opportunity, specifically as an example like DG. A good DG opportunity is a college campus or a hospital but they're not necessarily always located on the feeder that has some requirements for additional resources on it. So the utility can target something like that to provide that information to some of the end users there is some, you know, further optimization that can be made for the whole network.

MS. KELLY: Thank you. We have blue cards.

PRESIDING MEMBER PFANNENSTIEL: I'm sorry, did you have a question, Tim.

ADVISOR TUTT: I do have a question and it relates to the concept of a partnership with customers and the customers being able to sell energy or provide energy to their neighbors. Is net metering currently a barrier to such a future and what would you do about that?

MR. DOW: I don't know if we'd say net metering is necessarily a barrier but I think there certainly is, there is a regulatory change that would probably have to take place to allow that to happen.

PRESIDING MEMBER PFANNENSTIEL: Linda, have you finished your questions to the panel?

MS. KELLY: Yes, that's the end of the questions. Now the blue cards and --

PRESIDING MEMBER PFANNENSTIEL: We do have one blue card. Nora Sheriff would like to comment on the panel.

MS. SHERIFF: Thank you and good morning. Nora Sheriff for CAC and EPUC in terms of the distribution system planning and building the distribution system to meet the California energy goals. And my question is really directed towards PG&E and Edison.

I understood Edison to say that there's no anticipated problem in terms of integrating the million solar roofs from the California Solar Initiative program. And I'm just wondering, what about integration of the Energy Commission's goals for combined heat and power into the distribution system when you do your plan for the distribution system upgrade and looking at what the goals are.

MR. NEAL: That's a little more complicated. The reason I said there was not much of a problem for the solar roofs is that they tend to be a large number of small generators being connected relative to the feeder they're connected to. In that sense they're managed much the way new load is managed, it's a statistical issue. I don't worry about the fact hat a particular solar panel might go off-line at a time when I was counting on it.

But if I have -- The most economic combined heat and power units are larger. They're close to the size of the full capacity. Let's say I have a ten megawatt feeder with a five megawatt combined heat and power unit connected to it. I have to be very concerned about whether that unit will be generating the power at the time of the peak when I need it or not or whether I have any control over that fact or not.

So it becomes, each of those kind of become a case by case engineering study to do. I can't just treat that, you know, statistically when I'm dealing with a sample space of one. So it is more, there are more issues involved if one wishes to integrate a combined heat and power.

Also the combined heat and powers tend to be rotating machines which contribute to short circuit duty and have some other potential impacts on the system that the inverter connected systems do not have.

MS. KELLY: And PG&E?

MR. DOW: The issue, it's a matter of size. So it's a matter of impact from a system. The combined is very big and so you have to pay, you have to do a bigger study. When you do the solar panels they're localized. You may have more problems because you have more of them but they're smaller and they're localized.

MS. SHERIFF: And then could I ask a quick follow-up question, if I may? In terms of your planning of what you're going to do over the next year or the next five years or the next ten years. Is there a correspondence between what the utility has planned in terms of its procurement with its distribution system planning, maintenance and upgrade?

MR. NEAL: Are you referring to energy procurement or to hardware procurement?

MS. SHERIFF: I'm referring to energy procurement. The utilities' testimony in the long-term procurement plan proceeding and the forecast of, you know, 25 megawatts a year of combined heat and power for Edison over the next ten years of new CHP being added. And then for PG&E 28 megawatts of new CHP being added.

Is there, is there a congruence there between that procurement forecast and what the distribution system planning is?

MR. NEAL: You know, I think those levels -- And I wasn't involved and I am not an authority on the procurement side of it but, you know, that type of a forecast being spread over our system is something that we would be handling probably the same way we have been handling it up to now. These are ad hoc projects, we just engineer each one. It's well within our capability to manage, manage those.

It's getting to the point, you know. Getting to the place where solar panels are plug and play is one thing. Wanting to get CHP to a place where it's plug and play is quite another.

MR. DOW: And I don't know the answer to your question.

MS. SHERIFF: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. We do have one other commentor on this panel. M. L. Chan from KEMA.

MS. KELLY: Mr. Chan has a very short presentation.

DR. CHAN: Thanks for giving me the opportunity to share with you. It's almost kind of like a summary. I think we're talking about distribution system infrastructure. And I think basically I just want to kind of, in a certain sense, maybe put a little bit more of my spin on the things being talked about this whole morning.

I do believe that this could be driven a lot by the DGs, and particularly I think DG with storage, not DG on its own. And I think on renewables, they're going to form microgrids. And then we talk about the hybrid EVs and so on. It's going to call for an interface with some kind of home automation system too to do load leveling as Russ was talking about.

PQ is a concern. Service reliability is definitely a concern. Sustainability and global warming is driving a lot of these things, DGs and renewables and so on and hybrid EVs.

But I think that personally I just want to introduce something that I personally feel that you need to look at it from an elemental analysis when you look at sustainability and global warming. Because you may be looking at suppressing -- from an energy efficient viewpoint how much it takes from the chemical element into the end use.

That's how you want to analyze efficiency. Not just to focus on the particular aspect because it may take a lot more energy to really come up with something. Maybe a compact fluorescent light bulb, for instance, than maybe putting just a generating plant out there. So you need to look at the whole thing together. That's what I call elemental analysis.

And then of course, I mean, there's also the driver for efficiency. So this is just kind of a picture of what you see in the grid. You have the dispersed generation throughout. But I think that results in the requirements that you won't have more visibility to the distribution system. That's why we talk about all these sensors and so on.

In particular on the distribution system I would like to encourage looking into what are called inexpensive PMUs, which is already used for transmission. So then look at some inexpensive PMUs to get a good visibility of what is happening n the system.

And I can see maybe down the road that state estimators will be something that is needed for the distribution system.

More local intelligence control because I think right now basically we need to have a lot of, putting a lot of burden on the communications infrastructure just to do all this. Somebody was saying, yeah, it's an IT system, bring all the information back. But you want to put as much local intelligence as possible so that you don't have to depend on the pipe. If the pipe breaks then everything falls apart. So you want to have the local intelligence to be able to do that.

The Peer-to-peer kind of communication is important. And I think we talked about interoperability. It's also important to talk to all the devices.

And then I think the system has to be more hardened because we are talking about infrastructure, not just talking about an information system. So that's important. We've got to figure out -- we're looking at underground, composite material poles. Like what the Avanti kind of a circuit is demonstrating too. Maybe shorter response time with mobile data terminals.

And then I think the particular system is a two-way power flow. So something that puts a lot of burden into it. So how do you design your system protection. Because the relays you used to look at it in one-way. The power flow now, you're looking at a two-way direction so the whole thing needs to be reexamined.

So definitely condition-based maintenance and then we can talk about this whole differentiated reliability for different grids. Because when you're talking about microgrids, community development, it may be a cause of a different kind of reliability standard for that area versus a postage stamp type.

So that's why I think enabling technologies make this whole thing happen. There will be sensors, we can talk about communication infrastructure, enterprise IT system and holistic approach in the corporate culture.

And that leaves us the whole Smart Grid. AMR is the first level, AMI is the next level, and then the third level is where you do all the grid control and load management.

And that really is sort of a picture of what you will see. The sensors and the fuses. Going for the communications infrastructure and then the company is the enterprise information integration to utilize the information. So those three are really the basic building blocks for you to implement this new distribution infrastructure in the future. And then placed in there is the whole corporate culture of holistic.

So I just want to maybe say one comment about the bandwidth requirements. As you talk about AMR, yeah, I think it's a smaller pipe kind of application. But if you move up to AMI and into these grid applications you're calling for a larger and larger pipe. So that is really one of the major enabling technologies. Once you put a system in place that's this bandwidth then you can accommodate and make things happen. This part is not important given time.

But I just want to share the last slide with you. Kind of like what we call a mid-20th century grid. I think it actually came from the Global Environmental Fund. A lot of people, we see money is being spent on these energy-kind of ventures.

So basically what we're saying is say for instance there is some electromechanical kind of system, now we'll looking at a digital system. The one-way communication will expand more to a two-way communicating system. It's built for centralized generation now but in the future it will be all the DGs and renewables, support EVs and hybrids and so on. The load is moving around incidentally with the EVs. It's not a fixed load as before too, they move around.

The radial topology right now to more of a network, bidirectional power flow so it's very different. Right now it's all manual, it's going to be all automatic, semi-automated and decision-supported systems also. Eventually even selfhealing.

I think maybe just sort of the last times there. The limited price information to a full price information system down the road that the people will be responding. The customers and the utilities, they will be having this partnership together and making it happen.

So this is, I think, in a certain sense kind of pointing out where the research needs will be done on the high level. But I think I just want to kind of share that with you.

MS. KELLY: Questions?

ASSOCIATE MEMBER GEESMAN: How expensive are you envisioning an inexpensive distribution system PMU to be?

DR. CHAN: I think essentially those are cheap phaser measurements. I have seen vendors coming up with those. There is a vendor in Florida exploring that. As a matter of fact, I think Eric is here and then Russ. There is a project ongoing, an advanced feeder automation project. DOE is funding that and it's done over, going to be done at the Avanti Circuit Future. And actually I think PG&E is also partnership to that one too. Indeed we're exploring that.

I mean, they are, they are not the multi-hundred thousands, those kind of values. But the cost is still, maybe it's an older magnitude. Definitely lower than that one.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MS. KELLY: On the telephone are there any questions? Any final questions before we close for the morning?

UNIDENTIFIED TELEPHONE SPEAKER: No, thank you.

MS. KELLY: Thank you. Okay. Chairman Pfannenstiel.

PRESIDING MEMBER PFANNENSTIEL: Why don't we come back in one hour. So make it, make it an hour and five minutes so it will be 1:15.

MS. KELLY: Thank you.

(Whereupon, the lunch recess was taken.)

--oOo--

AFTERNOON SESSION

PRESIDING MEMBER PFANNENSTIEL: I think we'll start the afternoon session. We have a long afternoon ahead of us with a lot of good information. Commissioner Geesman will join us in a couple of minutes.

I did want to introduce Commissioner Byron who was not able to be here this morning. He was at a successful quest at the Senate Rules Committee. He has been approved by Senate Rules Committee and so welcome, Commissioner Byron.

ASSOCIATE MEMBER BYRON: Thank you, thank you Madam Chairman. Yes, I'll be around for another three and a half years or so. Thank you very much.

And if you don't mind I would like to acknowledge someone very important to me. It's kind of rare that she's here today but my wife was here supporting me and there she is. Debbie, would you just wave. Debbie. It's so rare that we get a spouse in here Debbie so thank you for coming. And if I don't --

(Applause).

PRESIDING MEMBER PFANNENSTIEL: Clearly the key to your success, Jeff.

ASSOCIATE MEMBER BYRON: Yes. I'll see you later.

PRESIDING MEMBER PFANNENSTIEL: Okay, full agenda. I'll turn it over to Linda.

MS. KELLY: Okay. Thank you everybody for returning. We do have a full agenda so why don't I go ahead and just start.

I am going to talk to you this afternoon -- well, just let me summarize. Basically this afternoon we're going to focus on research programs, challenges and opportunities to address distribution issues that we really identified during the morning.

I want to start with a brief discussion and an overview of the PIER program that I work for in the distribution area.

Jose Palomo will also give you an overview of the Distributed Energy Resource Integration Program and then Rachel MacDonald will finish with an overview of the new cross-cutting microgrid project that we're going to be jointly pursuing in the next few months.

The PIER Program is actively funding now nearly $400 million in research. It is a leader in low carbon technology and climate change response. We have a very active global climate change program. We address electricity, natural gas and transportation issues. Currently there's around $80 million in our annual budget and nearly $400 million in active projects.

We are divided into various focus areas that look at research from different perspectives. We have an efficiency and a demand response research program that looks at building efficiencies, industrial ag and waste efficiencies. Our demand response program has been very active in developing price responsive, demand response technologies and supporting those programs.

We have a renewables program. We have clean fossil fuel generation that is referred to as the Environmentally Preferred Advanced Generation program. The Distributed Generation program that I mentioned that Jose is the program manager for. We do combined heat and power.

We are now very much involved in transportation. We are developing a brand new transportation program that we expect to really make a difference here in California.

Energy Systems Integration is the group

that I belong to. Transmission and distribution are in that area. This says grid interconnection but that's work that Jose Palomo does with his Distribution Integration Program.

We also have a security program. It's not here on that slide but I did want to mention that. Our environmental program looks at air, water, climate and communities and is very active in supporting California policy.

Thank you. I'll get these lights right yet. I thought that what I'd like to do is --

Because I am the program manager of the Distribution Research Program and one of our primary research objectives is to focus on supporting the development of low carbon energy networks. I thought I would start my presentation today by explaining what a low carbon energy network would look like and why this vision of the future delivery system supports California policy objectives and I think really should be a high priority.

I don't think that all Smart Grids are low carbon energy grids. I think California has a unique perspective and we have made a strong commitment to low carbon reduction. So I think that this vision and this grid that we're looking at will help us get to that specific objective, besides some of the Smart Grid objectives.

I tried to explain this to my husband and he said, I don't understand this, so I thought what I'd do is just tell you what it would it would look like. It would have new interfaces and standards and regulations that would allow for the free exchange of energy services between the utility and its customers and make customer adoption of advanced technologies simple and understandable. No small challenge.

Distribution system design. We're looking at both the customer and the infrastructure in this vision. Distribution system design accommodates high penetrations of low carbon customer technologies. This is where you get into the efficiency, demand response, renewables, CHP, storage. Microgrids will be part of this vision and the plug-in electric hybrid vehicles.

And it's important that the grid be able to utilize these resources to improve its reliability and efficiency. They need to become, these resources need to become more than megawatts. Sorry Russ but I think that's the way it needs to be in the future.

Also this low carbon network will really need to integrate advanced technologies. And we'll hear about a lot of those today but these are really critical. Advanced sensors, automation, power electronics, communications and planning models that will help optimize the network in real-time, like the transmission system. The benefits would include increased distribution energy and resource efficiency.

It is really important that as we move to this type of a network that it be efficient. I think we can move there, and if we don't take care it will cost a lot of money. But I think if we do it right it will give us a lot of benefits and will actually be a low cost energy network.

And as Russ mentioned and all the people from the utilities. Customers I think need to be able to select their desired level of reliability and utilities can provide it.

And this I think is a key characteristic of what the low carbon energy network would like.

This slide is about technologies. You've heard about some of them mentioned in passing this morning as important and you'll hear in detail this afternoon about why these technologies are important and where they fit in.

I think it's important to understand that if these technologies are not developed and integrated to at least some extent into the new system Californians will have to continue to rely to a larger extent on central generation. I think that reliability costs, and I think this was confirmed today by presentation, you know, by utility representatives.

Reliability costs and impacts can be expected to grow as well. The amount of infrastructure that we have built will probably be suboptimal and increase costs as well. So we find that developing this type of resource is really consistent with our low carbon energy network goal.

And the program right now, the Distribution Program in the area of sensors, we talked about sensors. We're going to be working with developing a project now that we're hoping to get approved very shortly that will look at underground cables. This will be a unique opportunity. We have some very good professors who have very unique I think skills across industries to ask the right questions and to begin to discuss what are some of the new solutions.

But as a commitment to that project -- Because this is a nationwide project, this is not just -- Cables are not just a problem for California, they're a problem for all distribution utilities throughout the United States. As a commitment to that as a part of that research we are going to convene a large conference in which we are going to bring experts from the private and public industry to help us understand what the issues are help these professors find a solution that I think that everybody is looking for.

We are also looking at low fault detection with these sensors. This is a small project that we have going that says, can very cheap, tiny sensors detect faults at the distribution level. The question is, you know, can you embed the sensors.

But then I think another critical issue is, in the distribution environment will these sensors work? A lot of these sensors are being developed for homes now. The distribution system is a much different environment.

We're developing information modeling tools to help us understand where distributed energy resources have value and we're also doing some work looking at the financials with regard to that.

We're doing our value of distribution automation study and we expect to start research in the next few months on areas that are determined in that study.

We are also -- The key, big thing today that we're going to talk to you about is microgrids. We think microgrids are really critical to understanding what the low carbon energy network on a small scale can do first and then expand it to the larger grid as well as microgrids.

So we're going to need technology to make power delivery systems smart. But the low carbon energy network will not evolve without the full integration and ability to utilize customer resources that I think will be developing increasingly in the next five to ten years.

Customers, I think, are -- as a customer myself I know that a lot of these technologies can be very daunting and perplexing. But I think that we are all going to have to begin to think about what our role will be as we go forward.

So the challenge is environmentally and siting constraints -- environment and siting constraints will make it, I think, increasingly difficult to meet California's energy needs with the traditional central station generation and transmission. I think this is supported by policy as well, even if those were not issues I think our policy is moving to a more distributed system.

The solution. Decentralized energy resources could be called upon to meet a larger share of these capacity and energy needs. To ensure that these distributed resources are available owners and customers need to understand how to participate and have sufficient incentives to do so. To gain the maximum leverage and benefits from these resources the distribution system must be optimized to provide transparency and operating flexibility for these grid operators.

I guess it was on the 7th we had a DG workshop and Commissioner Byron asked the question about choice. And he asked Jane Turnbull, who is still in the audience today. And he said, do customers want choice. And she said that she surveyed her members of the League of Women Voters and 80 percent of them didn't.

And that doesn't surprise me but I think it gives us another issue to work on. Because I think it's important that these customers -- and I am probably one of them. I am not really anxious to do a lot of the things that Russ says I don't want to do, he's probably right. But if we develop the right technology, smart appliances, easy interfaces, I certainly am expecting that I would be willing to do this if I was given the right incentives, if I understood the programs and I had the technology to support those decisions.

I do think customers, and even residential customers, are going to need to be part of the low carbon energy network.

MS. TURNBULL: May I respond?

I am Jane Turnbull of the League of Women Voters. I do want to note that in fact our customers do like the idea of dynamic rates. They want to make choices in terms of their own personal options and use of energy. They don't want some individuals to be able to have a different set of rates. If it is going to be real time it should be real time for everybody.

MS. KELLY: No, I agree. Again, I think the programs are going to have to be transparent and everybody is going to have to understand them and they're going to have to be fair and equitable, certainly yes. It's all part of the challenge in figuring it out.

Let's see, okay. I lost where I am, sorry. Okay. So now that you have a better idea of what a low carbon energy network would look like and some of the technical issues and challenges that have been addressed.

I think I'd like to quickly review the areas that the distribution program is working on. I think that the areas that we are working on are consistent with some of the issues that were raised and I think this research will be helpful in addressing some of those issues. How we develop these initiatives and what technologies we develop I think in some cases is still to be better understood but I think we're on the right track.

Integration of DER and demand response. I think that we have a research project in which we are looking at developing modeling tools that will improve the visibility. There's a number of them around now but we want to improve the visibility in the distribution system.

As I mentioned, we are working with DOE to look at business case development with actually Southern California Edison. Let's look at from the financial perspective of the utility the cost of their traditional capital investments. And using the same financials let's take some DG, or maybe it would be some demand response, and let's look and see how those compare to the traditional utility resources.

In some generic cases already, we did some initial work, the time frames that they would defer some of these resources that Russ mentioned for seven to eight years potentially. I think we are going to look at them again and reevaluate the benefits in there and see, you know, if we can -- if those numbers can be improved. If they include societal values. But we are definitely going to pursue that some more.

Efficiency and DR. This is a project that we did with the San Francisco Co-Op and we're looking at diverse customers' opportunities to provide a range of support services to a particular circuit. And I think what we have to do now that we have some of those initial results, begin exploring how utilities can partner with these customers to take advantage of these resources.

Distribution automation. As I said, distribution automation is something that we found, we had a workshop, it is clear that distribution automation helps utilities with reliability now and it is clear that it will help them in the future improve their reliability.

The challenge that we have in this research project is trying to understand what other benefits we can get from distribution automation. Can it support the integration of DG? These are some of the public interest areas that we are interested in so we want to look, you know, from a public interest point of view, can automation provide other values beyond or building upon the value of reliability to the utilities.

Energy storage is clearly very important. We want to look at it at the distribution level. We'd be very anxious to include it if it was appropriate in our microgrid project to see how storage can support a distribution customer and activities and communications. You know, I think today we'll have a lot of briefings on how communication and data technologies are going to be critical to the interoperability of the system.

So beyond working with these core technologies that is an overview of the distribution program. What I wanted to do is to talk today about a new approach that we are taking. The distribution and distributed energy resource integration programs are joining together to do cross-cutting research projects and coordinate program activities.

We do coordinate, we do collaborate, but we're really focusing -- we think that the distribution and the distributed energy resource integration program, it's the connection between the customer and the distribution system.

So these resources and the distribution system are the core of a low carbon energy network and so we have decided that we are each going to pursue core technologies to make sure that in the distribution area and the DG area core technologies are still addressed. But we are really going to look and see where we can find cross-cutting projects that we can work on together.

We share a common vision. We have decided to do that, technologies that have been developed and brought to market that provide efficient, reliable and affordable energy to customers through a low carbon energy network. This is the vision that both our programs have.

We support -- Both programs support the integration and efficient use of low carbon customer resources, again CHP, microgrids, PV, et cetera. Cross-cutting research addresses milestones in both roadmaps. The work we are doing in my program and Jose's program can be seen on both our roadmaps. It supports both distribution research and DG research.

And then I also want to build on the collective experience of both programs. The DG program is a mature program. It has a lot of experience and it has developed a lot of very useful research and made a lot of inroads at the customer side for distributed energy resources.

The distribution program is new. We are just beginning to try to try to make these efficient connections. So Jose and I and Rachel, and Bernard Treanton who is part of our team, have decided to put our programs together and develop cross-cutting research.

So the next person to speak is going to be Jose Palomo. He is going to come up and he is going to talk to you about the distribution energy research integration program. And particularly he is going to talk to you about some of the microgrid work that he is doing.

And then he'll be followed by Rachel MacDonald who works with me on the distribution program and she is going to tell you some of the details about the microgrid project that our two programs are looking to develop in the spring of next year.

Questions? No?

On the telephone are there any questions? Okay.

MR. PALOMO: Thank you, Linda. Good afternoon everyone, my name is Jose Palomo, I work for the DER integration. I thank you for giving me the opportunity to present some of the work that we have been doing, some of the research work.

I am going to be presenting -- thank

you. I am going to be presenting some of the work that we have been doing in the microgrid research. I'd like to introduce Bernard Treanton who has been heading this project on the microgrids here at the Commission for the last, for the last few years.

My presentation is short, I have three major items to present. Basically the DER integration program overview followed by the cooperative efforts that we have with the distribution research program and then some brief overview of the microgrids research that we are going to cooperate on.

I'd like to provide a definition of my program. basically this is basically what the program focuses on, issues related to using relatively small-scale DG as part of the larger interconnected electricity grid. It's a simple concept but basically it covers, it addresses the electricity problems and addresses issues in the grid in California.

Through our research we have come up with what is something that we call platforms. Here's four platforms that we have identified as a part of our research and we invest PIER funds in research projects that basically address those platforms.

This morning Mr. Luther Dow pointed out that there's still some research that needs to be done in sensor technologies, power electronics, adaptive/protective devices and fault anticipation. So that basically corroborates our approach, research approach. We have come up with these, with these platforms on our own basically in analyzing the problems with the grid within the state and all the electricity problems.

So we have invested funds in grid effects with the objective of understanding the impact of DER on the grid and we have evaluated some of the effects of anti-islanding and voltage regulation and stability.

In addition we have been, we have funded power electronics projects with the objective of reducing the cost and improve the functionality of DER. And we have been able to develop some universal interconnection devices, modular highly-integrated devices for various DER platforms.

Everybody hear me better now? In addition we have invested funds in interconnection by streamlining Rule 21 and we are also going to be investing in advanced network protectors. And we have monitored DG with the objective of reducing the timing and costs for interconnecting DER to the grid.

Finally, market mechanisms with the objective of determining how rates and tariffs affect the market for DER. We are in the middle of assessing the impacts of AB 32 on combined heat and power and we are going to identify incentives for utilities to integrate DER.

The projects funded by DER integration have cross-cutting applicability in other PIER activities such as the distribution research program. And we have identified these coordinate research activities that provide solutions for each of the programs. In this case we have microgrids, regional demonstration optimization, energy storage integration.

This graph provides a time line of the investments that we have been making in microgrids. The Energy Commission together with the Department of Energy have been supporting microgrids since the year 2000.

In the year 2004 the Energy Commission awarded a contract to the Center for Electric

Reliability Technology Solutions that is headed by Lawrence Berkeley National Lab. By the end of this summer, this year, this project that started in 2004 is going to be finishing collecting data and we believe that we're up to the next step towards another demonstration and closer to possible commercialization of microgrids.

This next graph explains the operational concept of a microgrid. Basically they're DG, these are DG interconnected on a small grid and they provide a seamless islanding and re-connection. What that means is basically this grid, if you will, is connected to the major electric grid by this point of connection.

And in the case that there is a disruption or the microgrid is intentionally islanded this switch opens up and there is no disruption in the voltage or the current within the microgrid. So these sensitive loads continue working without any disruption.

In addition there is peer-to-peer. It offers peer-to-peer autonomous coordination among the micro sources. Basically each one of the DGs could augment each other's voltage and so on.

Another feature of this microgrid is it

offers and plug and play option, which basically requires no custom engineering. What that means is that the equipment can be connected to this network and it identifies with its own network and talks to the other components and basically they can manage the load by themselves. So one of the advances on this concept is the electronics, and also the software that manages this grid.

This is the actual application of the microgrid concept. It is being tested, this is a test bed in Columbus, Ohio and it features three small sources, each 100 kilowatts. The technology allows implementation of storage although at this test bed it is not, it is not being used. That's for future research.

In addition there is no power that flows onto the grid at this time but that is something that we would like to evaluate in the future.

I'd like to explain what you're looking at here. This shed basically is where these three Tecogen engines that run on natural gas are housed and they provide electricity to some of these switches. These are switches. And these are simulated load. What you see over here is the simulated wiring that would be typical of a grid or a small grid. The data is being collected by simulating voltages and variations of current and so on.

So the microgrid tests will be completed by this summer in 2007. The test results will be presented at an IEEE session. We will explore the -- the microgrid will explore the options for integrating a variety of customer-owned generation. Future projects will address technical issues related to exporting to the electric grid.

Additionally our PIER investments are being leveraged by the Department of Energy to advance the commercialization of the CERTS microgrid concepts. And the DER and the distribution research programs are planning to demonstrate these microgrids in California.

Before the next speaker comes up does anybody have any questions?

MS. KELLY: Thank you. Does anybody have any questions there?

MS. MacDONALD: Good afternoon, everyone. For the sake of time I'll just pretty much go through this as quickly as possible. My name is Rachel MacDonald and I work with --

MS. KELLY: Speak up.

MS. MacDONALD: Speak up. I work with Linda Kelly here at the PIER program in the distribution area.

As Jose mentioned we have current funding and research going in Columbus, Ohio. We're looking to bring that microgrid research here to California and that is what this is about.

At this time Navigant is interviewing utilities, customers, manufacturers and looking at various locations to put a microgrid application here in California. All stakeholders are welcome to contribute to this process and I'll provide that contact information at the end of this short presentation.

We are also part of this process looking to clearly define what values, value propositions, definitions and things that we're looking for to include in this work. This work is scheduled for completion this summer, June and July. End of June, early July.

Part of this, there has been a lot of discussion as to what a microgrid is. We just have a general definition that we're working with right now and that it is that it a group of technologies, obviously containing a generation source. They are interconnected and they can either be run concurrently with the grid, they can be islanded, they can be interconnected.

And we clearly know what we consider a microgrid not to be and that would be, for example, one single generation source serving one load. Or a group of houses, for example, with PV that are not connected in any way or have any form of control or communications group, group-wise.

Further in this work we are looking at what we are calling value propositions. They are basically values that are not mutually exclusive nor are they ranked in order. And they're going to help determine what is going to be the most optimal application for California. In this case many of them are often linked. For example, you would have reliability and power quality often going hand in hand together.

As part of this demonstration here in California we're looking for, obviously, this work to meet all the value propositions, fit in the criteria or the definition of what a microgrid is. And that it that it would be interconnected, serving multiple loads and have DER and other technologies. And to have -- We want strong customer involvement with the utility, with our end-users and manufacturers as well as cost-share. And the cleaner technology the better.

And we are looking to again have the scoping study done this summer by Navigant. That will be, again, June or July ETA of completion. And then we'll be taking that information and going forward with looking at a demonstration, hopefully to begin this spring 2008.

And if anyone that's in here would like to contact Navigant that may not have been contacted already the contact information is here. It will be Forrest Small or Stan Blazewicz of Navigant Consulting.

Thank you. Are there any questions?

Any questions on the phone? Okay.

MS. KELLY: Thank you, Rachel.

ADVISOR TUTT: Rachel.

MS. KELLY: Steven Moss. I'm sorry.

ADVISOR TUTT: One question. I didn't see storage mentioned in your list of items. Is that somewhere in there?

MS. MacDONALD: We are considering storage as part of the other technologies as well as demand response. I actually have that in my notes here but I was trying to get through everything. But yes, that's the other technologies including power electronics, communications and controls. The more technologies that a prime, optimal microgrid would be to have here in California the better.

MS. KELLY: I'd like to introduce Steven. Steven Moss has been involved in energy policy issues for more than a decade and a half. He served as an expert witness predominately on behalf of farmers and in a large number of proceedings in front of the CPUC and the California Energy Commission as well.

Steven is a member of our Program Advisory Committee for the distribution program and Steven is going to talk today about the customer perspective. And I asked him to come and speak about this because during the course of our PAC meeting and what you heard this morning Luther was -- I remember hearing Luther -- Luther just keeps worrying about all these customer generation resources are coming, how are we going to manage them and what we are going to do with them.

And then on the other side Steven as a

customer representative was concerned about as a customer I'm going to have this PV, this demand response, this AMI. What am I going to do with all this stuff?

So Steven today is going to talk about some of his ideas about as more and more customers begin to have these generation sources at their homes some of the ideas they might have to think for managing them. Steven.

MR. MOSS: Thank you, Linda and thank you, Commissioners. So yeah, I'm Steven Moss and I work with San Francisco Community Power as well as with an economic consulting firm.

And as opposed to going through specific research findings that we've had over the course of the years or working with PIER I thought I'd lift my head up from my computer and talk more, a little bit more conceptually from a customer perspective. And the customers I work with are farmers, families and small businesses. So not large businesses. It's a particular niche of customers.

That said, the research we have done for PIER to date has been provided as part of this workshop in the form of a paper that is going to be delivered at the ACEEE conference in July. And that research continues and I'm happy to answer questions about it.

As Linda mentioned, Luther has sort of said repeatedly in the workshops I've been in with him that it's important to look at the evolving relationship between utilities and customers. And he's using the word partnership, which I think is an apt word.

I wanted to do a little conceptual exercise around the term, duty to serve, duty to serve. A key underpinning of monopoly utility regulation is duty to serve. And the concept has been part of the regulatory process for decades and it has led to a variety of regulatory implications.

As the concept sounds, the round idea is that the monopoly of the utilities have an obligation to provide service to just about everyone no matter where they are, no matter who they are, no matter how much it costs to serve them. And as I say, this has shaped the utility industry pretty significantly.

It has certainly made it more expensive and more expansive than it would have otherwise been without a duty to serve model and its nose can be seen poking out of lots of different regulatory policies from providing low-income families rate discounts under the CARE program to placing a higher value on transmission and generation than one might actually think is worthwhile from a purely economic perspective.

On the other hand it has worked. We have equity in California and throughout the United States. Almost everybody has access to a utility system, to electricity provided by a utility.

Now over time the idea of duty to serve has shifted in sometimes subtle ways. Right now there is less of an emphasis on access and more of an emphasis on paying for what you get. And you can look at time of use rates and critical peak pricing as two illustrations of this new relationship between the utility and the people they serve. A different kind of duty. You don't just get what you want at whatever price you want it at. You may actually have an obligation to pay a different kind of price.

And a case could be made, and I'm not trying to make this case particularly strongly today. I think it's more of an interesting thought exercise and it bleeds into what research is important in the state of California and throughout the country. It could be that there is a more revolutionary change going on with the duty to serve concept.

Which is that over the next decade, or maybe a little longer or maybe a little shorter, that the duty to serve concept is going to be re-balanced. It's going to be re-balanced away from the utility and to the customer. Let me talk about that and why that is important.

A couple evidence of that is things like, again, time of use pricing or critical peak pricing. Demand response programs are another evidence of this. And under demand programs, as you know, a customer, willingly in this case, may be asked to give up megawatts kind of like a tiny, little utility. In some cases maybe even a, you know, moderate-sized utility.

Net metering on PV systems along with mandatory time of use rates is another concept of customer duty to serve. And the idea that we are going to have smart meters in every home and business takes it home essentially.

And the other concept that has been floating around today, which has been talked about now for awhile courtesy of the Department of Energy is the idea that we're going to have electric utilities breathing in and out of -- I'm sorry, electric vehicles -- breathing in and out of the electric utility system. Well now we've really got an integrated system or some kind of system in which duty to serve is all over the place.

So in the future that seems to be already unfolding rate payers don't look so much like passive consumers of electricity in the, you know, lights-on, lights-off kind of way but they are a two-part of the grid. And that means they have responsibilities and obligations that go beyond just paying their bill.

And the question is, what does a world in which consumers have a duty to serve look like? One thing is, and I don't really know this for a fact but I assume everybody around the table here is an engineer. And you can raise your hand if you're not an engineer.

It seems to me, and nothing against engineers, but it seems to me that in this kind of different relationship that the utilities look different than a corps of engineers-type structure, right. Historically a corps of engineers, they go out and build stuff, hopefully doing a good job of it.

And they look a little bit more, and I look around and I don't know that this is exactly an apt analogy, but a little bit more like orchestra leaders. Where they are asking for a different demand from here, maybe a tiny bit of resource over there and they have electric vehicles humming over there. So that they are more coordinating a wider set of perhaps smaller, diverse resources. I think it's already happening even in an engineering kind of construct.

So this again is the thought concepts. So the next step is, what models do we have in the world today that would tell us how this new system, if it does emerge in the utility system, is going to look like. And you can think about it. I mean, regional transportation systems come to mind. These are locked in an engineering approach. We build roads. But over time and increasingly there are options, right, whether it's mass transit or fixed rail or bicyclefriendly or pedestrian-friendly places.

And then the evolution very much like we are today with utilities, carpool lanes, congestion pricing. You know, systems that try to encourage a different sort of behavior in which there is a relationship between the driver and the road, really.

The health care system might also be an example of this, at least the best qualities of a health care system in which the patient is a partner with the doctor. But I don't want to take that too far.

The living, breathing example of this kind of relationship I think right now are water districts and irrigation districts in the state of California. And I don't know if you're familiar with these things but they're sort of quasi-public collections of farmers who agree to take care of shared resources, it started with water, now it's increasingly energy that could be their commodity, in ways that enhance the benefit of everybody in the district.

So water utilities. Members of an irrigation district are very familiar with being told to stop using water at a particular time, or being scheduled to use water at a particular time and have developed the means to be able to deal with that. Now water is not electricity. Water is kind of oddly like electricity in that it can't be stored, so to speak, but it can be stored, right, by reservoirs and conveyances, but it's a little bit of an odd commodity.

The energy systems in irrigation districts I think they merit examination. They are increasingly made up of -- I don't know exactly what a Smart Grid looks like in the future but what it looks like today in an irrigation district is, you know, they have a PV facility here, they have a natural gas-fired thing over there. They have a diesel engine that hopefully they're getting rid of next year. They're connected to the utility system. They're participating in some kind of critical peak program. Maybe they even own some hydropower somewhere. They have got a diversity of resources which is being shared collectively among the members of this irrigation district. So that's a model I think may look like what we're heading towards.

Now I'm moving towards, okay, so what

does this really mean to the utilities and I'm just going to throw out three possibilities. One is, you know, we have to plan the utility system potentially differently.

And I'm very sensitive to saying planning and utilities because I know utilities are very sensitive about their planning processes and have a good grip on them and I'm not wanting to get into their face about how they plan, simply point that there may be implications to planning. Better ways of communicating and more opportunities to participate by customers.

And once could make the argument that the utility model as it is currently constructed really is no longer apt for the future. That may be going back to the past where PG&E was a bunch of different tiny utilities, or something like that is really a more apt model.

Tom was talking about value of service and that they had discovered in San Diego that there are differences in people's value of services or provision of outages actually. But while there are differences in the frequency of outages and also in people's value of outages, this actually has been known by farmers for a long time. It's not a shock.

In the 1993 general rate case which I participated in with PG&E the farmer group I worked for proposed that agricultural rates be modified based on their value of service, which was rejected and has been actually proposed in general rate cases since and always been rejected for various reasons.

In the neighborhood I live in in San Francisco I did a, we collected some outage data. My neighborhood has higher outage rates than -- I live in Potrero, which is near the ballpark. We have a higher outage rate than say, Pacific Heights, which is near the Golden Gate Bridge.

You can find geographic differences. I actually was trying to find differences in low-income versus high-income outage rates, it's not there, at least in PG&E service territory so I was happy to see that. But there are these differences in outage rates that could be geographic.

The idea that you might have area rates, which has been floated again for several decades and always tossed out for, again, actually duty to serve reasons mostly. You know, you might actually having a more disperse system that's a little more geographically targeted.

So I just want to drive home a couple of points and I want to tell a quick story. I am not an engineer and that's partially why I am not talking about technology. I have a graduate degree in public policy. My first job out of graduate school I worked for the White House Budget Office and actually worked on health care, the Medicare program.

And I was over at the old executive office building. They have these meetings at the Indian Treaty Room, which I always found ironic, talking about a budget in the Indian Treaty Room. And we were briefing the director of the Office of Management and Budget and he asked a question, he asked a question of three people. There was his immediate subordinate, there was an economist and there was an old-time, wily bureaucrat.

And he said, how much of GDP will the health care budget consume next year? That was his question. And his second in command said, well, I think it's going to be about ten percent. And the economist said, well, you know, it really depends. The population is going up this way, the economic indicators are this. It could be ten percent, it could be twelve percent, I don't really know. You know, one hand or the other hand kind of thing. The wily bureaucrat kind of leaned in and said, how much do you want it to be?

It was a good answer. And I think that's where we're going with distribution planning. How much do you want it to be? How large a system do you want, what do you want it to consist of?

We have kind of predicated our utility system and our transportation system and our health care system and our water system in the state on building things for people as they come, right. We have a duty to serve. We have a duty to build roads, we have a duty to provide them with electricity, we have a duty to provide them with water, kind of in a passive way. And increasingly we know energy-efficiency, water conservation, demand response, toll roads, that's shifted but we haven't explicitly acknowledged it.

And what I am seeing in distribution planning is we're in charge of how much electricity is going to be provided and in what kind of way. And we have tools at our disposal to influence that, whether it be through pricing, through microgrids, or whatever. So to me that's a fundamental change in distribution and planning that could be happening.

And I'll give you more examples. I mean, I think for example in my hometown of San Francisco it is already happening in a crude way. Citizen pressure closed the Hunters Point power plant there and is leading probably to the closure of the Potrero power plant. Essentially a public call for a different generation mix, which then has cascaded down into calls for different types of distribution systems, energy efficiency, demand response. And I guess in San Diego they may be doing the same thing.

So that's planning. And again, I'm just giving you a concept. I'm not going to go any further or deeper than that.

Let's talk about communication real quickly. I mean, we're going to have smart meters everywhere. We're going to be able to communicate with customers. But the question is, what is the content of that communication? That's sort of the question that remains not quite answered that we all might have strong ideas about it. We are soon going to be able to communicate with customers in a two-way way. That's exciting. But is it going to be like TV 50 years ago, one show, or will HBO pop up somewhere? What does this look like?

I think one clue of this is that 50 years ago with telephones we had party lines, right. So you got on the phone and you heard someone -- it never happened to me because I was two young but, you know, you got on the phone and someone is talking and you had to get back off the phone.

Well, that's happening in the distribution system. Someone is on the phone. Someone is using the distribution system. And if you knew that they were on, your neighbor was on, you might be willing to get off if that was communicated to you.

Or if you knew in the case of demand response programs, you know, that if you got off the state wouldn't have an outage, you know, maybe you would do your part. So there's a lot to say about communication and I think it's beyond technology. We have the technology, the question is what are we going to do with the technology.

And finally is, how do consumers

participate in in this system? Right now our examples are photovoltaics and demand response. That's how people can participate as well as in pricing. These are crude things. I think we'll look at the current transition that we're going through with the utilities similar do we see that we see the solar industry in the 1980s. We're kind of moving through it.

I just want to point out that people critique both photovoltaics and demand response saying that they are only being adopted because they are heavily subsidized or they are being forced down people's throats. But I think it is important to acknowledge that a PV system that costs $50,000 that you pay $25,000 for on your home, you still pay $25,000. And that will never pay off, frankly. I mean, it will pay off 20 years from now when you've moved twice, right.

So we have to acknowledge that there are customers out there who are reaching into their pockets and they are paying to participate in the electric utility system. That is important and that is going to continue.

So I think the question then becomes, with the technology that we are talking about how do we, how do we match these things together? How do we use the technology in coordination with distribution planning, with communication with the customers in a way that gives people opportunity to effectively contribute to the grid?

And then I'll close by a comment on what Russ said about people feeding at the trough. I mean, again, as a customer you see these stovepipe regulatory processes where generation gets treated one way, transmission gets treated another way, distribution gets treated another way. And essentially it looks, it seems like we are pouring money into these things, just from a consumer's perspective. Whether that's analytically true I can't really comment on it, I haven't examined it, but it looks like we're pouring money into these things.

If the world is truly shifting towards distribution, or let's call it microgrids, then we need less of something else, right? If we have a lot more distribution that is able to handle itself through DG, DER, energy-efficiency, then why do we need all this transmission over here? Or why do we need these big, thick sources of generation over there? We might need some of it somewhere but at some point there needs to be a system approach to understanding what this whole beast is going to look like.

And I go back to the story I told you about OMB. What do we want this to look like? There is a value to a microgrid that is beyond just does it help the distribution system. It's also about society and institutional structures and economic benefits.

And I thank you for listening. Any questions?

ASSOCIATE MEMBER GEESMAN: Yes, Steven, if I may. You're not starting from a clean slate, a clean piece of paper, you've got a legacy system. That is especially true in the regulatory agency part of the jungle. You've got agencies with discrete, sometimes overlapping responsibilities but a particular focal point.

You've got in California three investor-owned utilities that serve roughly 70 percent of the load. A tremendous level of historic invested capital. And the way in which their shareholders are paid is a return on what's calculated to be their investment. Your future paradigm, shifting definitions of duty to serve, a variety of new relationships. How does the shareholder of any of those three investor-owned utilities get paid?

MR. MOSS: You know, that's a very good question and let me take two steps back and then try to address it. One is, and I think it was Russ that mentioned that, you know, they're having employment problems. You know, they're going to lose good people and they need to hire up and there are not enough people being graduated from these schools in order to fill these slots.

Well what comes to my mind is, who do we want to fill those slots? This is a decision point in a way. Like do we want an old-time entomologist at the University of California or do we want something more like a bioethicist? I think it's an open question for the utilities and only the utilities can really answer that in the context of regulation.

Luther mentioned that we need successes, I believe. We need successes out of the box. I think the state has had enough experience with grand schemes to try to change things and resulting in grand problems.

I'm a big fan, and this is what you guys actually have paid us to do, of smaller scale, test bed-type approaches where you can actually demonstrate effectively that whatever it is, the system that you're trying to do, works. So in our PAC meetings I brought up San Francisco as an example of a microgrid and there was dispute like well that's not really a microgrid. Maybe it could be a microgrid, I don't know.

But I think that the utilities investing in a small way in projects that demonstrate whether it's 14,000 homes or San Francisco or an irrigation district. And I think you asked the question about ownership of, you know, these infrastructure materials. Which if they did own or had a relationship with they do profit from. That there is no reason why the utilities can't feel like they are profiting and the shareholders are getting money from the evolution as it occurs.

If that's a reasonable answer.

ASSOCIATE MEMBER GEESMAN: So you see the utilities as a permanent feature on the landscape.

MR. MOSS: Well, the utilities are in ascendance, let's be honest. The utilities are on top right now. The regulators are trying to, you know, manage utilities the best they can. Whether that's appropriate or not I can't comment but I think it's the reality. It's that we are looking to the utilities to lead on this one and the regulators are trying to nudge them in the right direction.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Steve, I have to say that I really agree with your approach and I think that you're right. It is heading in a direction and we are watching it happen. And perhaps part of the reason we are all here today and we are all party to the policy report is trying to get ahead of it and shape some of it.

And I further agree that it's not just about the technology. But I am a little concerned still, there doesn't seem to be very much discussion of cost. And clearly given different answers to the what do you want it to look like question, have different price tags associated with them. As Commissioner Geesman pointed out, different winners and losers in terms of profitability. But I think from a customer standpoint probably sort of significantly different costs.

And as you go so many years into the

future then clearly this is a transition, it is not a, it is not a point where it is all going to happen quickly. We can shape but how do we get ahead to look at the costs? And the costs will be somewhat driven by the technology. You know, we get back to the technologies. It's going to be somewhat driven by that. So how do we think about that? How do we build in the various scenarios of different technology applications and adoption rates and what is it that customers are going to be willing to pay for?

MR. MOSS: Yes, that's really hard, that's really hard. And you know, you see it, you know, the presentation by the San Diego -- You know, whether or not it's worth having a microgrid approach. And you know, I was trained as an economist and one wonders what assumptions are behind every one of those numbers. Not to criticize that study but we all know how those studies work.

I think that right now, right now we have an opportunity. This is an evolution taking place that may become a revolution down the road. You know, five to ten years from now. Right now I think that there is an opportunity for the utilities and the regulators and you Commissioners to be piloting aggressively these technologies in the context of what the institutional or social structure it is that you want to experiment with.

In other words, I know that the Energy Commission has a mandate to focus on technology and really tries to drive its research in that direction. But if you can place that technology into a context, a regulatory context or a social context that you think might be the future or you might want it to be the future. And you can experiment with that in interesting ways throughout different service territories. I think that will give you the opportunity when the time comes to be able to make right choice.

You know, if we had smart meters in every household in Davis right now we'd know what we can do with smart meters, right? Well we don't so they're being rolled out on a mass scale. We have a lot of ideas about technology and we know what's kind of perking out of the water. Let's look at them in a real world setting and evaluate how that looks. And on that basis then we can develop analyses to tell us what it's going to cost. That's my best approach to it.

Other than that you just have to like take a big stick and whack on costs every once in a while and that's pretty crude.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. MOSS: Thank you.

MS. KELLY: Any other questions? No.

Is there any on the, on the telephone does anybody have any questions? None.

Okay, thank you, Steven.

Our next presenter is Eric Lightner from DOE. Eric has worked as a program manager for advanced technology development at the -- I'm sorry. Eric is program manager for advanced technology development for the Department of Energy for the last 16 years.

Currently Mr. Lightner is the program manager for Electrical Distribution and GridWise programs with the Office of Electricity Delivery and Energy Reliability. This program has been chartered to modernize both the hardware and the software components within the distribution system in order to address reliability and security concerns as well as to help move the electric delivery system into the information age.

Eric has been a member of my Program Advisory Committee from the beginning. I really have to say that we appreciate the support of the Department of Energy to send him out here. Your boss is Pat Hoffman?

MR. LIGHTNER: Yes.

MS. KELLY: Yes. Pat Hoffman has been very supportive of this program and some of the other research we're doing and we're working hard to develop some new collaborations, especially looking at Smart Grids, intelligent grids going into the future. Thanks, Eric.

MR. LIGHTNER: Okay. Thank you, Linda. I appreciate the opportunity to come here and share with you some of the research that DOE is currently funding. Again, my name is Eric Lightner, I am with the Office of Electricity Delivery and Energy Reliability. This office is a relatively new office, we're two, three years old or so. We basically were formed right after the 2003 blackout to started addressing some reliability concerns.

I thought I'd just give you some context for the technologies that I am going to discuss and introduce to you as far as within our office and what our office does in general. So again, Office of Electricity Delivery and Energy Reliability. We have three main suboffices, research and development, which is where I work in and what I'm going to talk about today, permitting, siting and analysis group, and infrastructure security and emergency response group.

The emergency response group, they're the ones that do deployments and do work with FEMA and all these other organizations when there's some sort of emergency that involves energy. The permitting, siting and analysis group, these are the guys that worked on the EPAC 2005 requirements and deliverables for the department as well as the corridor designation study that I'm sure you all have knowledge of, and then the research.

And we have four main areas of research. These are just the budget titles, more or less. Visualization and controls, high temperature superconductivity, energy storage and distributed systems integration. And what I am going to present today is some of the projects that are funded under the visualization and control piece as well as the distributed system integration piece, which more or less represent what research we're doing in the distribution area.

So in the distribution area really our goal is to modernize our distribution grid infrastructure and operations from the substation all the way down to the consumer. So we're really looking at technologies and the integration of technologies that can flatten the load curve, reduce the peak.

A summary of our funding over the last few years. This year we have approximately $8.7 million invested in the projects. And I might point out that this year we got no congressionally-directed projects, which was -- it looks like our budget was decreased but actually it's an increase if you do the math here and subtract out the congressionally-directed projects. So, you know, sometimes not passing a budget in October is a good thing and in this case it was.

This just shows how that funding is currently distributed amongst the different areas that we invest in, architecture and standards, monitoring and load management, advanced distribution operations, modeling and simulation, integrated demonstration R&D and we have a little bit of money going out into a solicitation this year. So I'm just going to, you know, do a whirlwind tour here of some of the technologies that we are currently investing in.

And hopefully you'll see that a lot of them address some of the concerns that we have heard here today, some of the needs that we have heard expressed by the different utilities. So it has actually been a good thing, I think, for me to sit here and listen to the three utilities that presented today. It makes me feel good about what we are currently investing in. I think we are starting to address some of those areas. You know, we're a far cry from addressing them all but we are starting to address some of them.

The GridWise Architecture & Standards. The gridwise architecture group is a group that's really focused on starting to address well what are the requirements for interoperability. How are we going to, you know, enable interoperability. Not only in the utility enterprise but across different enterprises. So for example when the utility equipment needs to talk to a building's automation system, how is that going to occur. What sort of information needs to go across that boundary.

We are also looking at, we're leading and facilitating the IEEE 1547 standards. So not only the standards development but we're also looking at validation and testing of those standards as well as working with different areas of the country to have them adopt IEEE 1547 in some manner.

So again, the GridWise Architectural Council is this group of volunteers from industry that we're just facilitating to begin to think about what are the issues in interoperability. And how it may start to address those and put some principles or parameters in place that we all can agree to so that when we start to integrate these systems we have a little bit of a roadmap or some guidelines to do that.

So in monitoring and load management technologies we have a few projects ongoing there. The one I highlight here, the Cable Diagnostic Focused Initiative is the one I'll speak of further. This is a project where we're looking at basically in-lab and in-service testing of diagnostic technologies, cable diagnostic technologies. We are trying to really baseline what their capabilities are.

So existing diagnostic technologies, both in the lab with some samples that have been taken out of utilities and sent to the lab. We're looking at you know, what do these different technologies, how can they perform in diagnosing how they failed. We are also looking at in-service testing as well.

So the bottom line with this project is we are trying to produce information for the utility industry that we feel would be helpful for them as far as exactly what are the capabilities for the different diagnostic techniques and on what kinds of cables will they work or not work. So it's more of a baseline kind of effort.

What we hope to get out of it, though, is to identify gaps in the technology and hopefully that will lead to areas that we need to invest research to get the additional capability that we're lacking in order to really come up with some better techniques to, you know, predict cable life.

So advanced distribution operations. In the DER integration area we have a project at DTE which is looking at integrating DER into their system for economic and for reliability reasons. they currently are operating both customer-owned and utility-owned DG into the midwest ISO energy market.

The one I have highlighted here is the 3G System of the Future. This is a pretty interesting project. I didn't have enough time to prepare a slide on it unfortunately but this project is looking at software agents and how we might utilize them as the platform to integrate DG and other resources into the operations of the grid. You know, we have this vision of interoperability and we're not really sure how it is going to work so we figured we'd test at least this software agent platform to see how might that help bring about integrating some of these resources into the distribution operation.

For the modeling and simulation projects we have several of those ongoing. The one that I am going to talk about is the results of the plug-in hybrid impact analysis that we funded at Pacific Northwest National Laboratory.

So this was kind of an interesting project. I guess about a year and a half ago or so we started kicking around the idea, you know, what if these plug-in hybrid things are for real and what kind of impact might they have on the electrical delivery system in this country. So we commissioned the study at PNNL and came up with some rather interesting results.

The parameters around this were well what is the maximum number of plug-in hybrids. If every car out there, every light duty vehicle out there was a plug-in hybrid. Do we currently have capacity to support charging of those light duty vehicles. So that was really the case we looked at, that limiting case. With today's infrastructure and tomorrow's 100 percent plug-in hybrids, could we meet that demand?

You'll see here that net petroleum imports are 60 percent in 2005. Of that gasoline, light duty vehicles represent 73 percent of those net imports. And the results of the study basically showed that up to 84 percent of all light duty vehicles could now be recharged with the existing capacity if you use a technique that is valley-filling.

So you charged -- We looked at two scenarios. You charged only at night and the other charging scenario was 24 hour valley-filling. So whenever there was capacity available you were able to charge. So that number was actually much higher than we thought it would be.

Again, this is the technique that we used. An average peak day load curve here. And the idea of valley-filling would be to charge your vehicles whenever there's capacity available. So if you utilized 100 percent of its capacity what would that mean for charging of vehicles?

And some of the assumptions here are important to note. That constrained valley, we excluded hydro, renewables, nuclear and peaking plants from being able to be utilized as the resource to charge.

Because our reasoning was, hydro, renewables and nuclear, they're used all the time whenever they're available, period. So they are not available for on-demand valley-filling like the other sources would be. And the reason we threw out peaking plants was because if you had to charge with a peaking plant you basically just busted the whole economics of the situation.

So we did this on a regional basis, NERC regions. And it is interesting to note that regions like ERCOT, they could charge -- the blue is the 24 hour valley-filling and the red is the nighttime so six p.m. to six a.m. You'll notice that ERCOT could support 80 percent of every single light duty car now on just nighttime charging and almost 150 percent if they charged all the time.

So it's rather amazing. And you also might note that California is one of the worst off as far as the ability to charge with the existing capacity that exists in this region. Which is amazing because this is probably where the initial adoption is going to occur.

So here is a more detailed one of this NERC region. You can see that there is really not a lot of capacity here to meet the demands of plug-in hybrids.

This is the results of the emissions analysis. We were a little bit surprised at this too. We thought it would be a little bit worse than this but basically this is a ratio of electric vehicle to gasoline vehicle emissions. So anything, you know, under one is a good thing.

And really only, you know, particulates and SOx turned out to be above one over here. So it's really a much better picture than we thought it would be. And the particulate emission, we thought that was handled more easily because what you're doing is you're moving the pollution out of the city, out of where all the congestion is, out of where the cars are and you're moving it to a more rural location.

But it's a point source now, it's just a generator. And that would even give us more I believe argument for investing in clean generation technology, clean central generation technology like clean coal. Because we have moved that pollution out of the cities into a remote location where we can address it as a point source, rather than trying to address it out of the tailpipe of millions of cars. So that's actually not as bad as it might seem.

Where we're going with this. This research ended at the end of last year and our final report just came out in December, I believe, of this past year and we're getting ready to embark sort of the next round of investigation in this area. We want to start to look at what are some realistic adoption scenarios.

Instead of saying, well what if every

car was a plug-in hybrid could we support it, that's a limiting case. Let's start to look at, what are some realistic adoption scenarios. So we're working with a major utility, DTE, as well as GM and Ford as a team to really come up with some more realistic adoption scenarios. To look at more in-depth what the technologies are, what really the charging requirements are going to be for different classes of vehicles and just do a much more in-depth analysis in this area.

So some of the integrated demonstrations that we're doing, I'm going to talk about two very briefly. One is a project supported by the Advanced Grid Applications Consortium. That is a consortium that DOE has funded for the last two years. It's a consortium of utilities that are looking at technologies that are very near commercialization. So they just need that extra kick, so to speak, to get over the hump and become a commercial product.

And I am also going to tell you a little bit about the Modern Grid Initiative Developmental Field Test that is ongoing or that is going to on-go in Morgantown, West Virginia.

So this is one of the Grid Application

Consortium technologies. This is a very interesting device and what this is is an autonomous storm detection adaptive relay. What it does is it's a device that you put at a substation. And it senses when there's a storm in the vicinity and it changes the relay settings at the substation to a storm mode rather than a normal mode and it does it autonomously.

So instead of, you know, sending a crew out to change the protection relays manually and then after the storm passes, you know, forget to turn them back or turn them back a couple of days later, this does it autonomously. So it detects when a storm is in the area, changes those relays for you and changes them back when the storm is not in the area.

It sounds simple but it has really been effectively demonstrated now at about six locations in FirstEnergy territory and it has saved a countless number of fuses and a countless number of labor hours of sending people out to change these settings. So it's really been -- It sounds simple but it has worked very effectively.

Now I have to go to that other. I had to have two presentations apparently.

ASSOCIATE MEMBER BYRON: So while you're switching, Mr. Lightner, can I ask, what is the detection scheme? Is it barometric pressure or some -- I have not heard of this but it sounds like a great idea.

MR. LIGHTNER: It's basically weather detection equipment, that's correct. So it's pressure detection. I believe it's -- I think it has wind as well. A couple of other weather devices and that's it. And it's connected directly to the settings on the relays. It's rather ingenious, very simple.

ASSOCIATE MEMBER BYRON: Thank you.

MR. LIGHTNER: This is the project I wanted to tell you about. It's called the Morgantown DFT, Developmental Field Test. It's a project under the Modern Grid Initiative. That's a team at SAIC that has, includes EPRI as well as DOE as well as the GridWise Architecture Council and a few other of these Modern Grid Initiative type people that have come together to design this demonstration.

And what it is going to look at is the phase one is autonomous reconfiguration of circuits to be able to recover much more quickly from faults. Phase two is going to take that one step further, no not only to do autonomous reconfiguration but what if we did autonomous reconfiguration with integrating DG and demand response into some of these areas.

So to even further limit not only the number of outages but the number of people affected by an outage. So the idea here is to isolate a fault as quickly as possible and to minimize its effect on outages for the least number of customers possible. And I am just going to flip through.

So phase one is just the Autonomous Dynamic Feeder Reconfiguration. So dynamically collect data from distribution feeders and, in case of a fault, will automatically isolate the fault and restore electric service using available capacity from adjacent feeders. And that's the unique part. So it's going to in real time calculate what that capacity is on an adjacent feeder and determine how much of the faulted feeder, how much of that load it can pick up. And then, you know, the different tie lines would be closed or opened accordingly.

So hopefully this will significantly

improve reliability indices, defer or avoid some planned capital investments. And actually in this case this is going to be, they wanted to add a new substation, Allegheny Power that is, wanted to add a new substation to support an industrial park. And if this project is successful they will not have to add that substation so they will avoid that upgrade for at least several years.

So this is a picture of Senator Byrd's new golf course in West Virginia. Not really, this is the DFT. So the way it's going to work is these are two circuits on this Westran substation here. And I'm just going to run you through a real quick demo of how it might work, how it hopefully will work.

So there's a fault in Zone 2 that's detected. The entire circuit trips at the substation. Load break switches open isolating Zone 2 from the circuit. The substation circuit breaker then closes. Zone 1 is now energized. The load break switch between Zone 3 and 4 opens. The load break switch between Zone 4 and adjacent feeder closes so now Zone 4 is re-energized. The load break switch between Zone 3 and adjacent feeder closes so now Zone 3 is re-energized. So all that is going to happen autonomously based on what the capacity is in those adjacent feeders.

So, you know, again, the next step on that project is after we can show that this autonomous reconfiguration really improves the reliability indices there then can we take that one step further. Now can we start to integrate customer-owned DG. Maybe there's some customer-owned DG in that faulted zone that could pick up part of that zone or what have you. So we're going to start to look at how can we utilize more and more resources on those circuits to not only improve the reliability but to, you know, make customers more happy.

One thing I do want to mention here was a solicitation that we just released I guess it was about two weeks ago now. We are hoping to award, make about six awards ranging in size -- we have about $30 million to invest total over the five years. It is not a whole bunch of money but hopefully it's enough to do some demonstrations like the DFT where we can show added value.

We anticipate making the awards in September but based on history I would say it's going to be a little bit after that. It takes a long time for these things. And that is going to be released and administered through the National Energy Technology Laboratory in Morgantown.

Another part of the solicitation or what the solicitation is about, it is basically about integrating resources into the utility operations. So how can we, again, bring to bear a lot of these resources and a lot o these technologies that we have been developing over the years into use, into operation in the utility.

In addition to that we also would like to see some developmental work in low-cost sensors for cables, cable application, advanced monitoring and distribution automation kinds of projects and also to begin to look at consumer information gateway development. So two-way communication between load-serving entities and electric loads within the consumer premise.

So I do want to briefly tell you about this GridWeek event that we had two weeks ago. This was an event that, you know, we thought it was, you know, past due. That we needed to start really getting all the different stakeholders involved in this industry together and get them on the same page and moving forward in the same direction as far as grid modernization goes.

You know, there's some many different initiatives and competing groups and whatnot out there that it's really hard to get your arms around all this and basically it seems to be counterproductive at this point. We're not really all moving in the same direction.

So we thought it was overdue to have some sort of event where we got all these different stakeholders together and started saying hey, what are the issues out there and how can we move forward together. That's really what GridWeek was about.

It more than exceeded our expectations. We had 634 participants. We thought we'd get around 300, 350 so almost double what we thought we'd get, we were very pleased. Which just goes to show that people are listening. These issues are now being discussed at very high levels.

Just a week after this event there was a hearing on Capitol Hill on Smart Grids. Tomorrow there is another hearing on Capitol Hill on Smart Grids. So I think we were successful in raising the attention of these issues over the past couple of years and it is finally starting to pay off.

People are listening, people realize that hey, we've got to start doing something about this stuff. So that's a good sign.

So this just pictorially shows you that, you know, what are you talking about when you say, hey, we're trying to get all these different groups together. Just look at that. It's a mess of all these different competing groups. Nobody really cooperating or talking. What we are trying to do is begin that discussion. Let's get everybody on the same page, Let's start working together.

And specifically my program works with a lot of different groups on the technologies that I just went over with you on and this is just a listing of those. So we work with the GridWise Alliance, which is an advocacy group for Smart Grids. We work with the GridApp Consortium, we work with NEETRAC, which is -- they're the ones doing the cable diagnostic focus initiative that I talked about briefly. Of course we work with the PIER program, the IntelliGrid group as well as the Grid Modernization Collaborative.

So that's all I have for you today. This is my contact information. Feel free to contact me with any questions you might have now or later. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Commissioner Byron.

ASSOCIATE MEMBER BYRON: Thank you.

Mr. Lightner, this is like old home week. I see a bunch of the members of the Program Advisory Committee that I was once a member of and I just wanted to acknowledge. I know Tom is on there and Russ and there may be others too.

I don't know a lot of the other program advisory committees but this is one of the most, it's got to be one of the most loaded ones that we have in terms of capability. This is really interesting stuff and I didn't really know that you were involved in these activities at DOE.

And I'm just curious, when I look back at your presentation and you were talking about in phase one all the goals that were included there, is power quality really something that is being addressed by the Smart Grid? I mean, is that just a term that we throw around here? Is there really something for, let's say, the commercial/ industrial consumers that can't stand interruptions of more than, you know, a quarter of a cycle or something? Are we really addressing that kind of issue with the Smart Grid?

MR. LIGHTNER: Well I think yes and no is the answer to your question. The answer is yes we're investing in energy storage technologies, which I think will have a big impact, or hopefully will have an impact that address power quality issues. Now whether you consider those to be part of the Smart Grid definition or not, that's what is debatable, I believe.

But we are, we do have a relatively modest energy storage program that we hope, you know. And it's utility scales energy storage so it's not, you know, a smaller consumer scale energy storage. That it will have a positive impact on power quality.

ASSOCIATE MEMBER BYRON: Okay. Thank you. And actually thank all of you. Like I said, I just think this is one of the most technologically loaded research advisory groups that we have.

PRESIDING MEMBER PFANNENSTIEL: Any other? Thank you.

MR. LIGHTNER: Thank you.

MS. KELLY: Just one minute, Eric. On

the telephone are there any questions? Nothing.

Thank you, Eric.

Our next speaker is going to be Frances Cleveland. Frances Cleveland is the president and principal consultant for Xanthus Consulting International. She has managed and consulted on information and control systems projects for power electric utilities for over 30 years covering SCADA systems, distribution automation, substation automation, distributed energy resources, automated metering infrastructure and energy market operations.

Frances also is the chairperson of the IEEE wireless working group developing recommended practices for wireless communications and power system operations. Frances.

MS. CLEVELAND: Thank you, thank you very much.

I'm afraid we're going to at this point head downward into the bowels of technology rather than up at the higher plane. But on the other hand I would like to say that some of the stuff that I would like to talk about really does help to address Steven Moss's issue of what do you want it to be. Let's see, do I just click? No, I do something else. Up and down, okay. Down, all right, thank you.

So I am going to address four issues. Basically I am addressing system integration or the issues of interoperability. So talking about the communications infrastructure, or more generally speaking, the information infrastructure that you need in order to make whatever it is that you want it to be actually happen. Because this is the underpinnings for everything that ultimately you may want to do. Excuse me.

So I am going to discuss this, obviously, in the context of distribution and DER as well as AMI. I am also going to give a very brief overview of what system integration and interoperability is because sometimes just the words themselves make people's eyes glaze over. And then I'll talk about some challenges and activities that are ongoing in this arena. And then really trying to hit the potential role of California in addressing these interoperability issues.

There are really seven principal characteristics of a fully modern grid. Now this is again addressing it from a technological point of view. But there is the ability to rapidly detect, analyze, respond and restore from perturbations. All of this requires communications information.

The ability to incorporate consumer equipment and behavior in the design and operation of the grid.

A grid tolerant of security attacks. This is not just terrorist attacks, this is inadvertent mistakes by people. People forgetting to close doors or to push some button or to turn on the system that would have determined that indeed there was a problem August 14, 2003.

In addition a grid that provides a quality of power consistent with consumer and industry needs.

A grid that accommodates a wide variety of local and regional generation technologies, including green power.

A grid that fully enables maturing electricity markets. So all of this is market as well as the technology of getting, you know, watts to people.

And a grid that continually optimizes its capital assets while minimizing O&M costs.

And this all comes from the program to accelerate grid modernization. That's a direct quote from that. And in reality, advanced control and communications technologies integrated with the utility distribution network provide the glue for achieving the requirements of the modern grid. So this is really saying, again, whatever it is that you want to do requires this information infrastructure glue.

In one sense my thunder was stolen here already by virtually all three utilities saying the same thing but that the distribution systems account for 90 percent of the outages for customers. So they really need to be addressed if you're talking about reliability. So it's a really critical issue to try to minimize that.

And less than 30 percent of the US utilities have distribution monitoring and control systems. In the past it just simply wasn't thought worthwhile. There was just too much distribution out there. You just had people running around and fixing things manually.

The trouble is that with the increased implementation of DER, demand response, AMI, doing all of this manually is just not going to be feasible anymore. It is just going to be an impossible task. So even if you wanted to continue doing this it wouldn't be feasible.

One sort of little picture that I like is the idea that we have at this point not just one infrastructure to manage. It is not just the power system infrastructure anymore. What we also have to do is to manage the information infrastructure. They are so tightly intertwined now that you have to look at them as one piece. They are one thing that have to be designed together, implemented together and managed together.

Okay, I'm going to have a very, very short tutorial on what is system integration. And the reason is because a lot of people don't really know what it is and this is a very high level one. But I think it's worth seeing because it's actually the same way that us geeks in the system integration world actually talk about it.

So how did disparate human groups communicate with each other? You've got Germans speaking German, and I won't try to read it out. The French speaking French, the Spanish speaking Spanish and the Martians well, yeah anyway.

What has been decided, for better or for worse, is that English is the common language. If you go to any international conference English is what is used. And this has been accepted because it became virtually impossible to try to translate, have simultaneous translations and interactions that were going on in multiple languages. I know it's still done at the UN but in any technical conference there is one language.

Similarly in system integration we're trying to establish common data languages for interoperating among computer systems. As I said, we use this term. We are talking about computer languages, data languages. So it's not just a question of making it simple, it really is how we think of it so that we use standards.

In our case we don't have English, we don't have a common standard language. We are having to create them. And this is some of the effort that is going on. And the creation is a messy process because you have to get everybody to agree.

We didn't have English so we're trying to create Esperanto but, you know, we've got different people. We've got not just the

Europeans we've got Chinese, we've got Africans, we've got, you know, who name it. So we are trying to create standards and we believe this is the way that we are going to get that system interoperability that we really need.

This actually comes from one of the presentations at GridWeek that Eric was talking about. That the US Senator Maria Cantwell in her act that she is introducing on reducing demand through electricity grid intelligence, it was presented there. And it in part read that it:

"-- proposes a broad definition of Smart Grid technology, which includes smart metering systems, demand response systems, distributed generation management systems, electrical storage management systems, distribution automation system --"

And there were some others. There was also one section in there that said Standards. And it said:

"Standard-setting provisions are considered to be vital to

ensure interoperability and
allow for smart appliances and
equipment."

She is talking in this case more about home equipment but it's the same idea everywhere. And then going down to the bottom:

"This section ensures that
Smart Grid systems and
components by different
manufacturers will in fact
someday be able to constitute
an electranet, Al Gore's term,
a community of intelligent
devices on the grid."

So breaking this down even further in using the language metaphor. Okay, there's the media. Many times when people talk about communications that is really all they think about is the media. Okay, are you going to use fiber optics or are you going to use wireless, are you going to use a broadband power line. What are you going to use?

But there is a lot more to the information infrastructure than that. There's verbs and the grammar that goes along with that.

It tells you when to send, what are you monitoring. Agents. The new idea of having grid agents wandering around doing things. They're verbs, they're going places, they're finding things.

In addition to that you need nouns. And nouns are the data and they're the measurements. They're the raw data that you get. They're the calculated data that you get. They're the files, they're the stuff in the databases. It's all of this stuff. Data management is a huge problem, particularly now that you're getting tons and tons and tons of data.

You've got to know what to do with it so you've got to have applications. Users, whether they're human but more often now computer applications, that take that data and turn it into information. Without that it's just lots and lots of stuff coming and you don't know what to do with it. So it has to be picked up and analyzed and converted into information.

So what are the challenges of interoperability? As I've said the standards can provide the interoperability needed across different systems. And some of the challenges nowadays looking at the communication media aspect, is WiFi wireless secure and reliable? Can broadband power line be used and where? What is the cost-effectiveness of different types of media for distribution automation?

These are all issues that really do need to be addressed that are not being necessarily addressed outside the electric power industry. You might think WiFi is, and to some degree it is, but it really is not being addressed for the needs of the electric power industry. So these are issues that still need to be done.

Okay, if you're looking at the verb side, the messaging. Security, cyber security is a big issue. Security by obscurity is no longer feasible. That used to be the thing, nobody cares about what information is being passed around in the power grid, but that is no longer the case. There is espionage, there is possibly terrorism, more likely there is some disgruntled employee who gets in there and just tries to disrupt things as they did a short while ago at Cal-ISO. So security is a big, big issue.

Network management. As I said, you can't just have data coming. You need to have --

You need to get that data to the right place in the right time and only then can it be turned into information.

Then protocol standards. Agreement on the standardized interfaces between systems. This might be where the grid agents come in. Where they become part of the protocol standards.

But the data itself, the stuff that is being carried along in the message, the data management in itself is another whole issue. it doesn't matter whether the data is going over wireless or broadband or fiber optic. It doesn't matter if it's going with grid agents or some other kind of messaging protocol. It's the data itself, that stuff, that information.

And the problem is that there is just such a vast amount of it coming from different vendors, coming from different utilities, coming from different customers, the ownership of the data is a big issue. It's no longer just the utility owns all the data that it collects, it is now coming from other areas.

How do you convert this? How to use it effectively. And there's data modeling standards. I won't get into that but there's a whole arena of actually modeling data. Not just modeling the power system but modeling data so that you can use it more effectively.

And then the last area are the computer applications. You know, we really need to move from just seeing information come from different items from the power system to a real-time analysis of the distribution system.

I know there has been a lot of work that has been going on in different arenas but not all of it has been focused on the real-time aspect where the real-time is looking at it within seconds of something happening so that you can actually do automated control of switches.

You can determine where the DER -- You know, what is happening out there in the network. Again, the utility is no longer really in control so much as they used to be so the information coming in is absolutely critical to managing the operation so it has to be more real-time than it used to have to be.

And then how to ensure power system reliability, efficiency, customer service, safety, environmental compliance that is going to come with the greenhouse gases as well as other things and access to the electricity marketplace. That's the time of use, real-time pricing, any of these other demand response type initiatives.

Okay, who is doing the research and crating the standards needed to address these challenges? And I'll start off by saying that indeed there are a lot of groups, some of them working with GridWise or through GridWise, many of them working separately, who are developing these standards. They all recognize that they're needed. But standards are useless until they're tested, validated, accepted by all of the relevant vendors and users, implemented widely and possibly even mandated.

Now one great thing about standards is that there's so many out there to choose from -- It doesn't work that way. You have to have a single set of standards or it won't work. It's okay to have American English and British English, that's good enough, but you can't have some very strange variety of English, it doesn't work.

So the media is being handled, the standards by vendors, utilities, associations. The IEEE is doing a lot. The industrial automation group ISA is doing a lot.

In the messaging, security and data management we have, to be quite honest, a whole bunch of this coming from the Internet and web standards so we're picking up on that. Ethernet, TLS, a lot of those terms that you might or might not know. Many of them come from the Internet. And that's fine and we can use them where we can but not all of them are applicable to the power industry.

The International Electrotechnical Council, the IEC, developed standards, and I'll say this carefully here, they developed standards that are accepted by every country in the world except the United States. So we get to pick and choose which IEC standards we want to implement but nobody else in the world does.

But anyway there is a tremendous amount of work going on there. IEEE developed standards, NERC developing particularly security-related standards. EPRI is doing R&D, obviously DOE as well.

Computer applications are typically more the vendors and the utilities we be need the standards to at least interface to them so we need to have a better understanding of those.

What roles could California play in addressing these interoperability challenges? And I think it's again the same thing that I was saying. California could study, test, validate and promote interoperability standards.

It is very frustrating for somebody -- I have been a consultant for 30-odd years and know that there are these standards out there. There are some really good standards out there. Many of them are collecting dust as some paper document somewhere. Others have been taken and sort of half-implemented over here because well, it was good enough, and what they have done is different from what another vendor has done.

So there really needs to be a much more concerted effort in handling the whole issue of standards. I'm hoping GridWise will in fact do a large part of that in this coordination. But it needs study, it needs testing, it needs validation and just promoting of the applicable interoperability standards.

So for medial we've got wireless, broadband power line carrier. In the messaging and security we need, we could use the Internet security where it's applicable but we need to take a look at that and really validate it. IEC has developed some standards along those lines and so has NERC.

Data management is probably one of the bigger, messier areas. There are some emerging IEC and IEEE standards on data management but data is really a vast area. And one person's data is another person's junk and so it's really difficult to get a handle on this. I think we are getting there in the IEC and the IEEE work but it's going to take a lot more, more effort.

And then in computer applications we really need to get some more computer applications running to do this real-time work. Once you've got that, once you've got the real-time applications running then you can decide what the power system is really going to look like because you've got the tools to manage it. That's simplistic, I know I'm sort of speaking at the high level there like Steven Moss but that's, that's okay too.

Okay, so questions or comments on that?

PRESIDING MEMBER PFANNENSTIEL: No questions from the dais?

ASSOCIATE MEMBER GEESMAN: I have a

question.

PRESIDING MEMBER PFANNENSTIEL: Yes, Commissioner Geesman.

ASSOCIATE MEMBER GEESMAN: Frances, looking at the way in which the transmission grid nationally has been a bit of a patchwork quilt in terms of levels of investment and how it's taken the 2003 incident in the Northeast to stimulate a stronger regulatory push for reliability how do you see these investments in the distribution grid where the outages aren't as cascading, don't attract as much attention? How do you see investment being stimulated there?

MS. CLEVELAND: That's a very good question. And I think one of the problems has been that in a sense there is no real financial incentive. Now that we've got sort of a market-driven electric utility industry there's very little incentive financially to play into it. That's why there has been so little investment in the infrastructure, the cables, the power lines.

And why -- I think even though the utilities every time I talk to them would absolutely love to put in new technology to increase reliability it comes back down to, well, we can't give this to our, either the rate base or to the shareholders. We just don't have the money for it.

And again it sort of does go under the radar screen a lot so that people don't realize that their lack of reliability is due to the distribution system.

ASSOCIATE MEMBER GEESMAN: I think it's one of the --

MS. CLEVELAND: That's as good an answer as I can get.

ASSOCIATE MEMBER GEESMAN: I think it's one of the real problems we've got to wrestle with here where you've got, I think, a very strong technological base and I think a customer community which probably has close to a critical mass of customers who would like to see things pushed forward but all of the inertia built into our regulatory process that we need to overcome.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Frances.

MS. KELLY: Are there any questions from the telephone? Anybody that would like to ask a question?

Hearing none, thank you very much,

Frances.

MS. CLEVELAND: Okay, thank you.

MS. KELLY: Our last presenter, we do have a panel but our last presenter is Mark McGranahan. Mark has been working with electric utilities worldwide in wide variety of technical areas. He certainly travels around. Whenever we here where Mark is he's in places like Greece and wonderful places like that.

His main focus has been in the areas of power quality assessments, system monitoring, transient and harmonic studies and economic evaluations. He is the co-author of a premier book on power quality concerns, electric power system quality.

Mark is both the national and international standards development vice chairman of the IEEE Power Quality Standards Coordinating Committee. Mark.

MR. McGRANAHAN: Thanks, Linda.

ASSOCIATE MEMBER BYRON: Mr. McGranahan, while there is a lull in the action I just thought it would be worth adding that it's just great to see you here. We get such high quality individuals here. Usually it's Commissioner

Geesman that is so well-read but I'd challenge him, if he has done as I have, and read your power quality book.

(Laughter.)

MR. McGRANAHAN: That would be impressive.

ASSOCIATE MEMBER BYRON: Well I have, Mark. And I think it's the definitive source on this so it's a pleasure to have you here today.

MR. McGRANAHAN: It's good to see you again also, Jeff. I was going to second Jeff's comment. I always enjoy coming out here. And I appreciate the invitation because I think the PAC that we have for this group are not only some of the best experts in California for this, they're some of the best experts in the world, really.

We did a project last year working with these guys from getting a utility perspective and the automation area has been tremendous. Over the year we've had great success. Some of the leading work that we did in power quality back in the day with PG&E and others, California was the leader in that work as well.

It's great to be here. My role now is I am the director of a research area at EPRI. I am in charge of the research area that includes distribution systems, both overhead and underground, and what we call the ADA program, advanced distribution automation, which I'll primarily be focusing on here. Also the power quality program and our IntelliGrid program, which cuts across distribution and transmission.

In these research programs we kind of deal with the system the way it is now and making it work better and trying to design the system of the future using some of the concepts that Frances just described.

Being the last speaker I could do my presentation by just saying yes, I agree with everything all you guys said. We've basically covered it. It doesn't hurt to repeat some of these things, they're important things.

You'll see on the second bullet there I used the same number that Russ used, the same number that Frances used. I can say we didn't work together on this. I think we probably all came up with that number independently. Russ said that's the Southern California Edison number. That's a number that I've got from various utilities in the midwest.

But pretty common that around 90 percent or more of customer interruptions are due to distribution events. I probably shouldn't say that 90 percent of the outages are due to at least primarily distribution events. About half the outages are due to secondary distribution, outages that affect just a few customers.

But our reliability indices, 90 percent of those indices are due to actually primary distribution events, faults on a primary distribution system. So there's a lot of opportunity to improve reliability working on the distribution system.

Again infrastructure. I was a little bit late this morning so I missed Russ's talk but looking through the slides it looked like he addressed this. The fact that, you know, cables are getting older, things are getting older on the system. There is a good potential that it is going to make reliability levels worse if we don't have aggressive programs to deal with those reliability impacts through replacement programs that are targeted and intelligently implemented.

automation in terms of impact for the investment is probably the best way to improve traditional reliability. I think Jeff was asking whether it would also improve power quality and we'll talk about that in a little bit because that's a little bit different question than reliability. But no question in terms of what regulators want utilities to improve, which is usually reliability.

That we can do that with automation. And that's one of the reasons why there's such an increase in investments in automation because we can do the business case for it. If the regulator says, we want you to improve reliability we can lay it on the table, this is how we're going to do it and it's the best way to make it happen.

Going to the next stage of really building a distribution infrastructure that can integrate distributed resources and integrate demand response. Some of the traditional things we're doing for automating the distribution system are not necessarily the same ones that will allow that so that's a little bit different problem. So that's kind of what we have to kind of tackle next.

All right. As I mentioned we did a project last year with Linda and Rachel and the

PAC in energy and environmental economics here in the San Francisco area looking at the value of distribution automation applications. Actually distribution technologies in general. It was a little broader than just distribution automation. We identified some categories for where the values can be realized.

I think it's a good summary of some of the benefits that can be achieved from investing in automation so that's -- We are looking at -- that's an active area of looking at, at the value proposition. I think you heard it from the Navigant work that's going on now. It's one of the key things that we need to look at when we look at microgrids and other things.

In the EPRI program in our advanced distribution automation program we look at the way the distribution system is today, which is basically radial circuits that supply load. And we see a vision, which I could throw the intermediate steps up there, of a system that like Frances said, has the communication and information infrastructure overlaid on the distribution system.

We have pretty much done that on

transmission systems. We haven't done it in a completely standardized way but more standardized than we have in distribution. In distribution we haven't even done it. We don't have communication out to devices out on the system. We don't have communication to the customers to implement advanced metering. It is one of the biggest investments in advanced metering programs, is the communication infrastructure.

So sensors to get more information about the distribution system. Intelligent devices, power electronics devices to make the system operate more efficiently. Sensors to tell when equipment is working and when it's not working, When it's nearing the end of its life equipment diagnostics is a big value proposition for these sensors out on the distribution system.

You see a number of projects described here today with looking at cable sensors. Cable sensors and understanding when we need to consider replacing cable or when it's likely to fail. Probably one of the biggest needs that we have, you know, in the aging infrastructure world right now is getting a better handle on what's going on out there and how close the assets are to the end of their life and can we use them for longer. You know, we don't want to arbitrarily replace assets that are working fine so if we can get sensors that help us understand that better we're going to be way better off.

So let me just -- One of the things that Linda asked me to do was just throw out some information about what technologies are there now as opposed to what we want to do in the future and then we'll talk about what's needed. And I'll start at the substation because the substation, we usually have some kind of communications to the substation. It's when we get out beyond that to the distribution system and the customers where it's less likely.

And we can do a lot at just the substation. A lot of utilities, our SCADA systems, our monitoring systems and our automation systems for most utilities go to a significant percentage of the substations. So if we look at these breakers here in the substation a lot of utilities can monitor and control those breakers from a central control center.

And there's more advanced things that we can do. A popular project that we're doing with quite a few utilities now is implementing using monitoring that we have at this substations anyway through smart relays or power quality monitors we get voltage and current wave forms that allow us to calculate where the fault is out on a circuit. And because we have communications we can get that information back to our office fast enough, do the calculation and on a map in a crew's truck tell them where we think the faults are. Overheard systems or underground systems.

This example happens to be ConEdison. It's an integral part of their operations now. There about 80 percent of the faults that they get on their underground cables they can locate within two manholes using this system. So what they do is they don't even thump the cables anymore. Those of you that -- what that is is to find the fault they put a high voltage on it and make the fault happen again and every time you do that you damage the cable a little bit more. So now they can get close enough to the fault that the majority of the time they can find it without even doing that and it saves them about an hour per event in terms of repairing that cable.

so it's very attractive. It's Progress

Energy and Carolina has been using it for quite a few years. There's a lot of potential to implement that. That kind of technology relatively inexpensive, using assets that you already have. And we're probably going to be working on something like this with the West Virginia project where we're doing the automation as part of the DOE project as well. So this is a lot of potential.

Automation, as I said there's a lot of technologies out there because the cost justification to improve reliability through automation is pretty clear. It's pretty easy to make the business case so we're seeing more and more automated switches going out on distribution systems. Similar systems to what Eric described in the West Virginia example that allow reconfiguration of distribution systems in zones and limiting the impact of an outage to the smallest possible number of customers.

There's quite a few technologies for that. DV 2010 is the research organization that is implementing technologies, originally with Cooper Power, now that organization is working with a number of other vendors as well. SNC has equipment, ABB has equipment in this area as well. So there's quite a bit of equipment out there. The challenge in a lot of these areas is making it interoperable so we can apply it in a more generic fashion rather than just applying a whole system from one vendor.

Sensors is a big area. As we mentioned, sensors for underground cable. Sensors for underground cables. There's companies working on optical sensors for distribution systems. This is a southern company as an example of a utility that has remote RTUs on most of their distribution systems and do a lot of work with trying out new sensors to reduce the cost of those.

A big cost -- When you're working on the primary distribution system one of the big costs in automating a system is the sensors. Sensors on the low voltage systems, relatively inexpensive. Sensors on the, once you get up to 13 kV the sensors start to get pretty expensive and then you've got to communicate to them as well.

We've got a project at EPRI that we've been working on on cable technology itself. Making the insulation, the dielectric for the cable have a better voltage withstand characteristic so that we can build smaller cables that can handle the same power and voltage or build the same size cable that can handle more power. So there's a lot of potential with this.

Dow Chemical has just licensed that technology and they're going to be building this cable and we're going to be trying it out so we're very excited about that, using nanofillers to improve the dielectric strength of cable technology.

I mentioned that a lot of utilities are justifying automation, Hydro Quebec is a good example. I like their slide so I used this one when we had our international workshop at Hydro Quebec last year. They have a program that has been okayed by their regulator to automate virtually a very high percentage of their distribution systems over the next five or six years. It's kind of a nice cross between research work and actually putting the stuff out in the field.

The primary driver initially is reliability but over time we want to plan the system so that we can also use that infrastructure to integrate. They are interested in conservation voltage reduction, interested in increasing efficiency, integrating distributed resources and so on.

So looking at the business drivers and working backwards -- there's actually two slides they use here. One is you look at the business drivers. What applications do you need to accomplish those business drivers and what information do you need to accomplish those applications. And then when you actually implement it you know you go the other way.

International coordination. I do travel around. Actually I haven't been to Greece in quite a few years but I was in Indonesia recently. But the international coordination is very important and very active. The European SmartGrids program has a tremendous amount of research momentum looking at automation, new control technologies for distribution systems.

I just did the work with Singapore a little bit and Deepak Divan from Georgia Tech and myself were over there and they just initiated a new research initiative. They have a program called the A-Star program there and they are investing $300 million Singapore dollars, which is about $170 million US dollars or so, over the next five years in the Smart Grid.

And their objective is to make -- they can see the importance of the Smart Grid internationally and they want Singapore to be a place that is going to supply those technologies, at least for Asia if not the whole world.

They already have probably the most reliable power system in the world, they don't need a Smart Grid. The system is amazing the way it works now. They don't even talk about outages, they talk about voltage sags, and they try to get the number of voltage sags that customers experience per year down to less than one and a half, which is, as Jeff probably understands, is a great number. Their voltage sag numbers are our outage numbers.

But they know that the business potential of these technologies in the Smart Grid area are very important and they are going to spend the money to get the expertise in Singapore to make that happen. So it's a very international area.

And the coordination to accomplish things that Frances was talking about, we've all got to be talking the same language if we're going to take advantage of technologies that are coming from Singapore and China as well as technologies that we develop here. And if we're going to sell technologies to Singapore and China it's got to be, they're all going to have to be using these same protocols and languages to make that happen.

So we have -- Every year we conduct an international workshop in the advanced distribution automation area. ConEdison hosted the first one two years ago and Hydro Quebec last year. This year it's in Raleigh, North Carolina in October and I'll just mention that.

This is our five areas of research that we work on in the ADA program at EPRI. The technologies themselves, sensors, communication infrastructure, control systems aspects and then putting it all together in making it work as a system. So that's kind of the research areas that we like to talk about.

So with that I'll finish up by just summarizing what I think are some of the areas where we do need research and it should be a summary of what we've heard from virtually everyone today.

Interoperability. There's two kinds of interoperability that we talk about. There's interoperability kind of at the device level when we talk from device to device and being able to control that device and collect the information from that device. That's a set of standards that fall under this banner of 61850 in IEC.

And then there's interoperability at the systems level so that your outage management system can talk to your customer information system, can talk to your geographic information system, can talk to your disturbance monitoring system and they all can work together.

That fault location case that I described is one of the best examples of that. When we go to work with utilities to implement that fault location, taking the voltage and current wave forms to calculate the impedance to the fault is simple. That's just, that's just a simple calculation.

The problem then is integrating with the electrical model of the distribution system to figure out all the possible locations where that could occur, integrating with the operations database because we need to know which breaker operated it to know which feeder it was on in the first place. And then integrating with the outage management system because that's maybe predicting a section of the circuit anyway.

And now we're looking at the electrical model we come up with five possible portions of the circuit where it could be because we've got all kinds of branches. But if we combine with the outage management system that's probably already predicting which branch it's on. So in the end if we can get all these systems talking to each other we can access information from all those systems in a common way, we can make the thing work.

Right now we end up with a $100,000 project with each utility to make it work because we have got to figure out how to talk to that outage management system and that electrical model. The standards really don't exist for doing that. Once we figure out how to talk to GE's outage management system then we're all set and we can talk to this particular model we're all set. But in the distribution world there's lots of different vendors and they all have their own, their own systems.

So interoperability at the distribution

system level is over magnitude more difficult than it was at transmission and really warrants a lot of attention. I like Frances's suggestions about you've got to -- you can't just write the language, you've got to -- we write the language and when we try it out in the field we realize we forgot ten things that needed to be in the language. You know, we go to access this piece of data and we've got no name for it. So you've got to try it out in the field and make it work.

The communication infrastructure itself, there's a lot of potential there. I don't know if we're paying enough attention to using public infrastructure for that, you know. My own personal opinion is that there's a lot of potential there for research. Obviously there's security issues and reliability issues but I think there's a lot of potential to try that.

When we were up at Hydro Quebec last year we heard from Nova Scotia. I think it was Nova Scotia or New Brunswick that uses the public cell phone system, GPRS, for all their distribution automation. So every device that they control out on the feeder circuits has a GPRS receiver and transmitter on it and they don't have any investment in communication infrastructure, they just use the phone company.

But at the same time every one of the phone company's cell towers is on their list of priorities for restoring power just the same as hospitals. So it's a sign of, it's a way that they are cooperating that if there is a big outage they're going to go get the -- you know, those cell towers can go for a few hours with the battery backup that's there. And the utility is going to make every effort to get them back in service as quickly as possible, which benefits all the people in the area as well as their own communication infrastructure. I think that kind of model has potential that we should look at a little bit closer.

Integration of technologies. I think the cable, the nanotechnology in cables is a good example of crossover to other industries and being able to do things. Eric mentioned a project that they have with Infotility and ConEdison looking at the 3G system and agents.

And that raises a very good question that I think deserves a lot, a lot of research. And that is, where should the intelligence be in this infrastructure where we're going to enable demand response. You know, we're going to have intelligence all the way down to the customers thermostat. And we're going to have intelligence to the substation, we're going to have intelligent devices out on the distribution system.

What is the relative responsibility for optimizing the system performance at all those different levels. And that's a big question that we have not figured out yet, you know. We're kind of used to being a central computing industry. We like, in the utility industry we like to bring all the data back and solve things centrally. The grid agent project is the opposite extreme. It's solving everything, basically every local agent is very smart and knows what to do locally with the information it has while still having the opportunity to optimize things at a higher level.

But there's a lot of potential for figuring that out. Looking at what the objectives of the system are going to be, the way we want it to work with demand response kind of the questions that we got. How do we want it to work is going to help influence, you know, where we want the intelligence to be. And trying out different models for that makes a lot of sense.

And finally we heard the topic of planning tools brought up as well. That's kind of a pet one of mine. What we want is -- And this is a big challenge. We don't have planning tools that even work with automated distribution systems. We don't really --

We plan distribution systems in our traditional way to make sure that the feeders have enough capacity to supply the load based on the load factors and everything else. Taking into account any stochastic approaches to deal with automation and the fact that this feeder might have to supply a portion of another feeder and what's the likelihood of that.

As well, you know, going to the next stage of demand response and the whole customer's influence where probabilistic approaches are going to become even more important. And those have to go into the planning tools at the distribution level. And then equally important, they need to go into the planning tools up at the transmission level. And that's also a question is how much transmission do we need if we're going to have a widely distributed, you know, system with lots of generation all over the place.

But we can't even answer the question unless we have planning tools that can evaluate the performance of the system with those distributed resources and how it affects the system performance all the way up to transmission. So those are some areas that I think have still a lot of need to -- We haven't figured them out yet.

So with that I'll open it up for any final questions.

ASSOCIATE MEMBER BYRON: Mark, I guess this is a similar question to what Commissioner Geesman had asked earlier. But back to your business drivers. I think you had said that reliability was the one that you could make the best case for, the best business case for. How do you make that case to, say, regulators? What is the argument for the cost-effectiveness of implementing? Ultimately what I'm asking you, what is the argument for implementing the Smart Grid here? These kinds of tools, these kinds of controls.

MR. McGRANAHAN: I think there's been a lot of studies that have been done on the cost of outages, the value of fewer outages, the fewer number of minutes interrupted. So you can take those kinds of studies that put a value for different types of customers on the outages that they experience.

Translate that to the savings that you would realize if you can improve that reliability and compare that directly with the investment in automation. Kind of the automation for which the technology already exists now and usually it works out pretty good.

Then there is still a question of whether the regulator will -- Even though that's kind of a theoretical look at the value of that, that reliability. You still have to get the regulator to sign off that we agree that customers in our service area that we're regulating really value reliability the way you're, you know, the way these studies say. And if they do then they usually will allow you to make those kinds of investments.

But that automation of say automating the primary feeder circuits is not the same as the next level of automation, which is the whole communication infrastructure for advanced metering and enabling demand response.

The business case for that is a lot more difficult because we can achieve the reliability numbers without AMI. You don't AMI to achieve the reliability numbers, you just need to automate the feeders themselves on the primary. It's a much lower investment than AMI.

What we need AMI for is to make the who system smarter. And those benefits are they are efficiency, they are optimization of the system, they're equipment diagnostics using your assets better. All of those, you can add them up and they still don't add up unless we put something on top like the demand response benefits at the society level. And that's becoming less controversial but even a year ago it was still pretty controversial.

ASSOCIATE MEMBER BYRON: I'm sorry that I wasn't here this morning when perhaps this was discussed or addressed but are there any examples in California where we have implemented a pilot or a distribution system that has some of these capabilities?

MR. McGRANAHAN: The Southern California Edison system is practically all automated with this kind of technology, you know, so they're ready to go to the next level. They've achieved the reliability benefit of this kind of automation of the system that Eric described and some of the technologies that I put up there.

You look across the country, virtually every utility at least has some pilots in that area or plans to look at it. It really varies, the investment. Southern California is up at the, you know, high end. San Diego has invested quite a bit in the last two or three years would you say, Tom, automating?

DR. BIALEK: Since mid-1995 but really heavily since '99.

MR. McGRANAHAN: Okay. And PG&E is jumping on it now in a pretty aggressive fashion as well. So that's being done. It's not -- It's a question of whether you want to plan that automation if you haven't already done it. Southern Cal and San Diego did it long enough ago that, you know, they weren't talking about AMI too much at the time they were doing that.

But now utilities like PG&E, like Duke is very active in this area back in the East. Since they haven't really automated beyond the substation at all now they can talk about AMI and distribution automation in the same sentence, you know.

So if there are any economies in the communication infrastructure to be realized they can, they can look at them at the same time rather than investing in a radio system for automation that probably doesn't have the capacity to help you much with AMI. So you have to look at your AMI communication infrastructure virtually completely independent. And then maybe it works out economically it's best for it to be independent anyway. But at least you could look at the commonalities if you haven't, if you haven't already gone down that path of automation.

ASSOCIATE MEMBER BYRON: Thank you, Mark.

PRESIDING MEMBER PFANNENSTIEL: I may jump into the question of the value of service calculation. I know that's -- We have tried to do that for 30 years and it has always been murky at best. And it's been a number that you can kind of move around at will to justify whatever you want.

MR. McGRANAHAN: And when we try to add power quality to it it's ten times more complicated.

PRESIDING MEMBER PFANNENSTIEL: But if you take it from the other direction, back from the customer perspective. Rather than what the utility wants to do but rather what the customer is willing to pay for or to avoid paying for, if you will. If you get to a cost-based real-time pricing kind of rate scheme where then the customer is largely telling you how much reliability he or she is willing to pay for.

And I know that that's probably no less murky in terms of trying to decide on what those exact prices are on a real time basis. But you can come to some approximation of that, can't you, which then gives you some sense of how much of this you want to build into your system?

MR. McGRANAHAN: Well, having pricing structures that deal with reliability, we have never been very successful at. We have tried things like premium power and things like that have never been very good.

Real-time pricing is more what we talked about earlier of just reflecting the actual costs of generating and distributing the power and translating that to, you know, the people that are paying it. So making the costs more transparent.

Really having nothing to do with reliability, more just the real-time costs of the power.

That has a lot of benefit in that it puts the incentive to save or not save, you know, matches that up better with the costs.

PRESIDING MEMBER PFANNENSTIEL: It does seem like with AMI you have clearly incredibly more information about -- you know, two-way information.

MR. McGRANAHAN: Oh yes.

PRESIDING MEMBER PFANNENSTIEL: What the customer is using and cost to the customer.

MR. McGRANAHAN: Yes.

PRESIDING MEMBER PFANNENSTIEL: And therefore if you're building higher levels of reliability into your system and you could pass that through in pricing that is -- it's a more sophisticated system than we currently have. You're right, it doesn't give you all that information.

MR. McGRANAHAN: Reliability improvement, power quality improvement, better asset management are all kind of side benefits of AMI that you get. For the most part in this country, other than industrial customers like where Jeff used to work, they don't want to -- the systems are more reliable than we're willing to pay for already, you know.

Customers are pretty happy with the reliability. They don't want to pay higher prices for any reliability higher than what we have now. That's at the residential level, you can correct me if I'm wrong, Steve. Reliability improvement does have benefits, there are benefits, but customers are not willing to put a lot of -- your average customers are not willing to put a lot of investment into that.

Efficiency and helping global warming, customers are much more incented right now to help pay for that than they are for improved reliability, I believe. And that's what has changed the whole paradigm in this in terms of the, you know, people looking at it. We've tried to make the case for reliability, you know, year after year and residential customers are just pretty happy with the reliability.

If we can just -- And that's why regulators tend to focus on things like the worst-performing circuits and places on the system where customers really aren't happy with the reliability and getting those fixed. Around the country that tends to be a focus of the regulators rather than -- and not letting the reliability deteriorate. Those two things more than improving the reliability. So reliability benefits of AMI are really, we need to think of those as a side benefit but a benefit nonetheless.

PRESIDING MEMBER PFANNENSTIEL: Well, that's AMI. But are you saying that the entire distribution improvements of which we have been speaking all day?

MR. McGRANAHAN: No, I'm not. And reliability, as Russ put earlier, if we don't do something about the aging infrastructure the reliability is going to get worse. So automation and understanding what's happening with that aging infrastructure is a way to prevent that. So a lot of these technologies are important just to maintain the level of reliability that we have today and we're going to, we'll have to do something in those areas.

But be careful of putting too much weight on the reliability number, at least in terms of incremental benefits when you're already very good. You know, you've got one interruption per year average per customer.

PRESIDING MEMBER PFANNENSTIEL: Thanks.

MS. KELLY: Thank you, Mark.

That ends all our presentations. This last panel, I think I want to use it to help us summarize. I'll join the group. The first question is I am going to ask everybody to summarize and prioritize their recommendations. And then the rest of the questions just should go to giving us some recommendations and ideas going forward.

ASSOCIATE MEMBER BYRON: Madam Chairman, I'm going to have to excuse myself and I'm sorry I couldn't be here for the whole day.

PRESIDING MEMBER PFANNENSTIEL: Thank you for being here and congratulations.

ASSOCIATE MEMBER BYRON: Thanks, thank you.

MS. KELLY: Also I want to -- I have these people at the table but Steven and, Steven and Eric, please, if you have a comment on any of these questions if you would just come up to the podium and just answer.

We've heard a lot of technological recommendations today. The lists are long for everybody. And this one, this first question here asks, what are the critical technologies that will enable the power delivery system to handle and optimize the use of significant and concentrated penetrations of renewable distributed energy, storage, CHP, demand response and eventually PHEVs. I note that I am not talking about reliability here, I'm talking about in this type of integration.

Could you give us one or two, your top one or two so that we an get can idea of what the priorities are. Maybe three. And see if that'll give everybody an idea of, you know, what we'll have to focus on first.

And then also prioritize them in time, near-term technologies. Let's assume we don't know where we're going yet. I think we clarified that today. We know things are changing. In your priorities one or two would be something we should do in the near-term and what should be left to be considered and evaluated for the longer term.

I can just start and go around.

Frances.

MS. CLEVELAND: Well, taking it from the point of view of somebody who is involved in the communications integration world I would say that at advanced modeling of the power system, the distribution power system in this case, along with the communications to bring in the data that you need to make the model correct, is probably the most important as the basis for then moving forward.

If you have an accurate model of the distribution system including the DER, including not only real-time information but also the actual connectivity of the power system, the cabling, the capabilities of the transformers. All of this information, which I think any utility here will say is probably one of the most difficult things is to make that data actually accurate.

But if you could get it up to the level where it's at least reasonably accurate then you can, with this computerized model of the distribution power system you can then move forward and do your operations, your planning. You can actually do demand response because you now know and can monitor what the, what the results are of any demand response action and so forth.

So I would say that's probably my number one. It's rather large because it includes a lot but I'd say that's my number one focus.

MS. KELLY: Tom.

DR. BIALEK: I've got a number of them here. I'll try to keep them short. But I think clearly one of the things from what I have seen is the issue with regards to the aging infrastructure, addressing that old system, rejuvenation of the system. Keeping it in a state where we can actually connect things to it.

Absent that it is going to be awful difficult to, you know, think about how are we going to change things significantly when we're focused strictly on the aging infrastructure issues. So really a robust, physical system.

I would agree certainly with the better analytical tools. Not just across the planning perspective but tools from looking at diagnostics, looking at automation, looking at decision-making and how we do that, asset management in general. A more extensive use of a fully automated system as time goes on I think is also going to be very critical to doing this.

And the one I think we can't really forget, which is just the whole issue with regards to rate design and reliability levels. Well what do customers really want? What rate designs do we need to give them to empower them to actually go forward?

MS. KELLY: Thank you.

MR. DOW: I have two issues. I think the aging infrastructure also is the first point. If I had to look at what we have had to do here our focus today is trying to keep the system intact. And as long as we're trying to do that as long as all our management energy is going into that process we are not having time to look toward the future. So that's the first piece.

And I think the second piece, if we're going to -- if we are going to do this other work, and we are going to do this other work, then we have to be able to have interaction between the customer and utility, so we have to have an open protocol. So I would say those in that order.

MR. NEAL: This is Russ Neal. The three things I always say on this is first we would need, if we want to stop treating distributed generation as a nuisance to go away whenever there is a problem and start using it as a asset we need three things.

The first is we need to have an idea of what we want to do with it. We have to have a control model. What would we like it to do so it would be an asset under various contingencies. Second we need a communication infrastructure to make it physically possible to do those things. And third, we need a win-win business model for hat type of integration.

MR. McGRANAHAN: I think I'll second Frances's comment. I'd like to focus on planning tools. Modeling has two parts to it and if we get the models right and we can use them for planning purposes then we can also then through say automated means of keeping those models up to date use them for real-time state estimation tools as well, which we're going to need for really optimizing the way we operate the system on a minute by minute basis.

I think that communication infrastructure is inherent in the second, in the real-time aspects of it but the modeling aspect is an important requirement right now even to get going.

MS. KELLY: Any other comments? Eric or Steven? Okay.

The second question here. I think we have talked about automation. The critical question here is, what policy and regulatory changes would help provide incentives that will encourage utilities and customers to invest in promising technologies.

Again, you know, we've talked about this, you know, directly and indirectly. But for us to really understand what the major barriers are it would be, I think really important. So if you could give some suggestions about what you think these changes should be or would help that would be helpful. Frances.

MS. CLEVELAND: Well I'll pick up on that with something that was discussed at GridWeek a couple of weeks ago in that there is what was termed a hairball of policies and regulations.

(Laughter.)

And I think that, you know, we may be talking here about California but I think it's impossible to move forward very cleanly towards getting incentives for either both utilities and customers, and vendors for that matter of equipment and systems, without some movement towards undoing or clarifying or pulling apart this hairball of policies and regulations.

DR. BIALEK: I had a few here again. I think from our perspective looking at more of a long-term vision instead of focusing on this based on a three-year rate case cycle. It would be a real positive step. That is a problem for trying to move a lot of these things forward because if every three years you are back in front of the Commission arguing as to why you need dollars to invest in this it's a fundamental problem.

I had mentioned earlier, just things like accelerated depreciation schedules for some of the Smart Grid technologies allowing these things to move through our systems faster.

And then I would also say, you know, support for -- A lot of these Smart Grid applications, et cetera, are at this point in time really conceptual. There's a vision of what it will look like, what the system will look like, but we don't really know exactly how it will look like. So support for R&D programs to try to flesh those details out.

MR. DOW: In a similar vein I support also, the support to acknowledge and recognize that this is a risk and something is not going to work. And we should not be therefore penalized for things that don't work.

And without any details just that there needs to be an incentive way, a way to incent utilities to be innovative and that there is some reward at the end for being innovative and not be penalized for failure of a product or a project that appears to have a good basis but doesn't work.

MR. NEAL: And similarly there are two things really. One is what I was crying about earlier, some O&M funding for utility-based research,

And second is when we do assume risk of let's go try a circuit of the future instead of a conventional circuit that entails some risk either there needs to be some kind of a reward mechanism or some kind of protocol that recognizes that we're taking on a risk in this set of activities and that we aren't going to be, you know, held to the standard, how dare you take that risk type of a thing. We'll be protected in some way from that.

MR. McGRANAHAN: The UK has a regulatory program, I think they call it Innovation Fund or

Innovation Tax, depending on how, which utility you're looking at. But it basically requires that utilities set aside around one and a half percent of their revenues for R&D into innovative technologies. And essentially they can get virtually all of it back to apply their technologies on their own system on things like the circuit of the future and stuff.

For some companies like Scottish Power it's worked, you know, very well in terms of advancing the technologies forward. They have a big problem with integrating distributed wind because they have long, you know, relatively weak circuits and lots of wind and everyone wants to put wind farms up. But they have basically a limit because of voltage regulation issues, they just can't put them on distribution systems.

So this is -- They are developing new control strategies and system voltage control strategies to implement that. And it's all falling under this Innovation Fund so it is one example of a regulatory approach that can help move the industry forward.

And I think just going out on a limb and taking a chance, you know, like the Germans with the funding for photovoltaics are good things, you know. They cost money, they cost society money but they move the whole technology forward.

Germany is the leading solar panel producer in the world now. And the jobs that it's produced in Germany just in terms of the photovoltaics industry, you know, by some estimates I have seen have exceeded the cost of the whole program just in terms of the economic impacts to the country. So sometimes you get side benefits that you don't even think about because 50 cents a kilowatt hour is a lot of money to pay for power but it's had a lot of other benefits.

ASSOCIATE MEMBER GEESMAN: Do you have a sense as to what the electric utility industry spends on R&D per year as a percentage of revenue? This is a little bit of a trick question because I know the, I know the answer.

MR. McGRANAHAN: I think it's in the order of a half percent, isn't it? Maybe even .1 percent, I don't know. It's in the half percent range I think. If you look at the list of industries we're right down at the bottom.

ASSOCIATE MEMBER GEESMAN: Yes, I have been told that it's at the very bottom.

MR. NEAL: Our rate of return is fixed on the investment so we would be risking investments.

ASSOCIATE MEMBER GEESMAN: Right, right. And in California what we have done is socialize that budget and transfer it over to the PIER program. But I think we end up with -- well, I won't go there. Thank you.

MS. KELLY: Well I will because the next question really just was trying to start a discussion about research. The one question was, given the amount of research being done by the manufacturing companies what research should be done by public government agencies and what should they focus on?

I think today Eric and I have given a review of the research that these two organizations are doing, you've given an overview of what EPRI is doing and Frances has reported on research that is being done, you know, in a variety of sectors on interoperability.

So with this question the question I have to ask is, have we missed anything between us? I mean, it isn't necessarily what PIER should do. Is there something that after you listen today you say, nobody is doing this and one of these organizations should pick it up. I mean something that wasn't even mentioned.

And then the other question, maybe we can just answer that separately, has to do with some of the utilities now are doing a little more research. Are asking for research money in their rate cases. And earlier in the day there was a question about the research that Luther was doing and so you can answer this however -- these two questions however you'd like.

What research should utilities be doing? Or what should they consider doing, especially with regard to rate cases and thinking about getting back into the game again. Is it going to be something that is going to grow in interest or is it just some small amount of research that you will ask for in rate cases and that is probably all you want to do? Frances, you won't probably know that but --

MS. CLEVELAND: Well, I am not going to try to speak for utilities but I'll try and at least address the previous one, which is the amount of research being done by manufacturing companies. Often that type of research is very specific to their products and to their end game, their bottom line.

It is, in fact, one of the reasons we have so much trouble in the communications information arena, is that there is very little effort, and certainly very little funded effort, to try to develop these cross-vendor, cross-product standards. There is no money being made in standards development per se so that it is very difficult.

And we do -- What we do is we get together groups of people from the vendor and utilities and consultants to come up with the standards but then there is almost no money at all to actually test it, validate it across vendors, validate across utilities and other users because the vendors don't have any interest.

You know, maybe once we develop the standard, it's there, they will implement what they feel of it. But they don't try to do that true interoperability. That really needs additional funding from some outside source.

DR. BIALEK: I'm sorry, I'm just writing a few down here. I think the first one, research by public/government agencies, I've got a number of things. As I mentioned before that the whole issue with regards to reliability service levels, I think that could be something that could be done at a public level. Broader than just, you know, the utility going out and considering its customers. Because I really think that that's one area that as we move forward with some of these Smart Grid technologies that we're going to have to really go in and answer.

Other ones that I put down here, things with regards to rate design issues. What would, what is a proper incentive mechanism, what should those levels be, how do we incent customers? The whole discussion with regards to cost and benefits analysis. I know we have gone through several sort of rule-making at the CPUC and just trying to get to that with regard to technologies.

And then lastly, research with regards to the performance of existing technologies. Are we getting really what we think we're getting from them. So, you know, we invest X dollars in particular technologies, are really given that.

In particular I know this came up at the PAC meeting, would we sponsor that looked at performance of, for example, residential photovoltaic systems. We today estimate what the residential photovoltaic systems are doing by the basis of what is coming out of the SGIP program for larger systems.

And the real question is we know that not everybody is going to have their PV reoriented due south and providing the optimal system performance. So the question really comes down to, for the money that we're investing what are we going to get out of it?

As far as from the utility perspective, clearly I see for SDG&E the whole alternative service model. How can we look at utilizing other resources, customer-owned resources, whether it be through AMI or just going directly to customers or working with developers? Additionally other ideas that are collaborative to advance basically the industry such as, you know, the Smart Grid initiatives.

And then lastly, you know, we have our own, internal operational needs that really do need R&D, do need to be funded. And they certainly are public interest per se but they are certainly utility interest. One could argue by logical extension if they reduce rate therefore it's public interest but, you know, that's one of those sort of Catch-22 arguments.

MR. DOW: Having been an ex-EPRI employee for awhile I'm a very big fan of collaborative research. I think collaborative research brings a lot of points of view to the table and it shares, it shares the successes and it shares failures. But I really support that.

I don't support, unfortunately, the idea of trying to develop the product. So I think that we set an incorrect expectation because a product is a very difficult thing to -- But collaborative research for knowledge and then how you use that knowledge within your own company is important.

From a government/public agency perspective, I think as Tom mentioned, these issues associated with society and public benefit and tariffs and all of the -- those are not necessarily technical issues but they're still -- What is the value of service and is it different from different place? Or what is the value of reliability? How do you do that? Sometimes when a utility does it it's seen as self-serving.

And what research should utilities be doing? And I don't mean to be flip but I think they should be doing the thing that they think is important. PG&E is doing a lot of research in plug-in hybrid vehicles. There's some research in storage. Not doing much in the way of distribution.

We do, the distribution research is sort of very small items. We're working with NEETRAC working on cable diagnostics, EPRI work on paper insulated cable diagnostics. So I think it's where the, it's where the major focus that that utility wants to do. And I guess it's -- You called it utility interest.

MR. NEAL: One of the topics that has been coming up a little bit today is this issue of quality of service and variable quality of service and should somebody pay a little extra for a little better service. And I think a lot of that is generated from the sensitive customers who, you know, they're getting a voltage dip and it's causing them a process problem, where other customers their lights flicker, they could care less type of a thing. How should that be handled.

One existing means of handling stuff like that is our added facilities charges. If somebody wants -- we do that today, for instance, if instead of having one source of feed you want two sources of feed with a transfer switch. You can pay a little extra for that under the added facilities.

If we had a box that you could give the customer under this added facilities charge that would support his voltage during these voltage upsets on the system, sort of like we talked about on the Avanti a little bit there, that I had that as a developed product right now, that when the customers call me in and say, I'm having all this problem with all your voltage dips, I could just say, well then buy this little box on added facilities and it will solve your problem because it's all been developed.

Right now I don't have that available. There's a few vendors that have some things but they're way overpriced and not really ready for prime time at this point.

So I would think one area that it would be a little bit of R&D type of a thing that somebody could do between utilities and some of our joint efforts here would be to try to develop some product like that that would give, that would be an optional box that somebody could buy and hook up on their side of the transformer and when the whole system gets a ten percent voltage dip they only get a five.

Maybe it would be an SDC, maybe it would be a DVR. There's a number of technologies that are promising in this but there's none of them that are like off the shelf available, I can guarantee this will work.

MR. McGRANAHAN: In general I'm in agreement with Luther that it's probably not the right role for EPRI or the utilities or even the CEC to be developing actual products because the manufacturers do that the best. And they do that the best especially when, you know, they can see the potential market for the product.

So things that affect the market for the product like the incentive in Germany and things, that is something that you can do. And R&D that relates to the cost benefits, R&D that relates to the application of the products I think is very good. And we heard that a couple of times and I think we need that. Manufacturers have less incentive to really address all the issues with applying the products.

Interoperability is definitely a role

that we have to take because the manufacturers have very little incentive. They have actually incentive to go the other way and make their systems proprietary because then you have to buy everything from them.

So things like the Southern California Edison work in the AMI area to try to define some standards that allow vendors to build the next generation products in a way that they'll be interoperable with each other and with the systems that have to gather the data from them is still a very big area.

Having said that I think that R&D, fundamental R&D that's way out for things that we haven't, the manufacturers kind of haven't thought of yet, if we don't fund that at a public level then a lot of times it doesn't get done. And traditionally that has been a role for DOE. I don't know if CEC sees themselves as a role in that area.

That A-Star that I mentioned in Singapore. You know, a lot of their research in that is in that area. It has a dual purpose of generating talent in the universities and the country as well as doing very forward looking research that might, might come up with some, you know, some magic bullets down the road. But there has to be outside funding for that kind of stuff because manufacturers don't do it.

And areas like -- I think storage is particularly an area that's interesting to look at because there everyone knows that storage is the holy grail, you know, to make the system work, to make demand response work, to level the load factor to make everything work together.

The manufacturers know it, we know it as a research organization. The money that we spend in the storage area as a research organization is nothing compared to what the manufacturers are spending. Because they know that if they come up with that battery or that technology that is economic in the storage area that, you know, that they'll make a killing commercially.

So we can continue to study that, that's another good example for enhancing the talent in universities and stuff but we don't need to spend the money. The research is going to get done, you know, by the Mitsubishis of the world and what have you. They are going to continue to try every way they can to improve the cost benefit, you know. The cost of ratios for storage.

MS. KELLY: Thank you. Is anybody from the audience -- I didn't see any blue cards but does anybody from the audience want to make a comment?

PRESIDING MEMBER PFANNENSTIEL: Linda, I actually have a couple of blue cards.

MS. KELLY: I'm sorry, I didn't --

PRESIDING MEMBER PFANNENSTIEL: And here comes another one.

MS. KELLY: Sorry.

PRESIDING MEMBER PFANNENSTIEL: That's okay. Richard Brent who originally was here to speak on this morning's panel but then he had to leave and put in a card this afternoon. But he is gone. Jim Skeen.

MR. SKEEN: This light is green so I guess it's on. I've just got two comments. One, Linda's presentation this morning talked a lot about a low-carbon footprint but I didn't hear any numbers or any goals. I didn't get a sense of whether it made a one percent difference or half it, cut it in half. So I think that's a pretty ill focused way to think about those programs.

And the other thing I'd like to say is,

I've lived in my house for maybe 28 years and I have had one outage. And it was because I had a fruit tree that eventually uprooted the service to my house. So it is possible to have almost perfect service.

And I used to be the distribution engineer in the area where I live so I know why it's good. The cable from the substation out has never been overloaded. It's had fast relays. It has never been subjected to a lot of I-square-T and there's a lot of overhead line.

And the trouble man that I used to work with have passed on to the new trouble men that are doing the work now. The trees along the route to my house are trimmed and all the fuses are appropriately sized. So that's just attention to detail.

And I guess what worries me about the discussion, I'm interested in all this new technology and I have had a lot of fun with it over the years, but you haven't -- by the time you address replacing all the poles that Luther listed that are over 40 years old you won't have much money left over, will you?

PRESIDING MEMBER PFANNENSTIEL: Thank

you, sir. And Charles Toca on the phone.

MS. KELLY: Can I just make one comment?

PRESIDING MEMBER PFANNENSTIEL: Of course.

MS. KELLY: Yes. With regard to quantifying. I think that it's very interesting you mentioned that because I am just working on developing metrics to help us quantify the value of a low-carbon network. It won't be easy. We know a lot of the values are hard to quantify.

As you've indicated, what is the value of PV. But I think that we're -- we think that it is an appropriate objective and vision and we are in the process of developing metrics to help us understand what the value of this will be and what the costs will be as well.

PRESIDING MEMBER PFANNENSTIEL: Thank you. On the phone, Mr. Toca.

MR. TOCA: Hi, this is Charles Toca. I'm a (indiscernible) for VRB Power System, which makes a large flow battery, utility size of ten megawatts. I was interested in the comments on energy storage and I appreciate, I think it was Mark's comments, on storage being the holy grail.

But I wanted to speak to Russ Neal's

comment and ask a question along those lines. We were talking about, how can storage and some of these technologies be integrated. Russ mentioned earlier, I think it was him, that he said that every time the utility pencils out distributed generation for distribution that it didn't make sense, it didn't work out economically. But Russ also mentioned plug-in hybrids and that sort of thing might work economically because they help to utilize under-utilized generation right now.

I was wondering if he could speak to if there are plans by any of the utilities to look at large energy storage in place of or as a DG plug-in for distribution and to include those kinds of economics into the process to see if it does make sense in that case for a distribution application.

MR. NEAL: Well yes, this is Russ.

We're very interested in that. It's always been, like we said, obvious that if you had a substantial, economic, reliable energy storage thing that you could do load leveling on your system there would be a lot of better capital utilization going on and that sort of thing. We're interested in that. We have not seen a proposed energy storage system at the distribution circuit level that was attractive at this point.

DR. BIALEK: This is Tom Bialek. One of the other things, in particular one of the things we've seen, is that in the applications where we have actually used distributed generation on our system to support substations and/or carry customers the things that we found, the particular applications were at some remote locations where we ran diesel generators. And clearly given sort of where diesel is going it becomes problematic.

And certainly from -- And there is no natural gas in those areas either so you sort of have a little bit of a problem. But energy storage, storage batteries, flow batteries, whatever, some of those kinds of technologies really have to become a little bit more attractive in those areas.

Because if you can get them in there and the cost is reasonable then we can do the same, we expect we'll be able to do the same thing as we do with DG. But at this point in time, again just like Russ said, we haven't found an application where it has been cost-effective.

MR. NEAL: If I could just give an example. We've got Catalina Island 30 miles off the coast. It's got three megawatts of load, something less than half of a circuit. And we're considering running a 33 kV cable all the way out there instead of using the distributed generation out there as a better choice. So it kind of gives you an idea of where it pencils out.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Is there anybody else here who would like to make comments? Anybody else on the phone?

Yes, please come up to the podium.

MR. SCHWARTZ: Thank you, Commissioners, I'm Peter Schwartz. I just wanted to make a quick comment. We had discussions of R&D funding and how can we stimulate that and what are some of the drivers for that. And some of the comments that were mentioned earlier had to do with the creation of markets either through sort of smart rates and tariffs.

And I think those types of incentives can go a long way to just stimulating private industry to do R&D. We have heard that manufacturers do R&D pretty well themselves. So if you help create the environment and do it over a life cycle or a time frame that is long enough for the investment the market will tend to move rather quickly. In many cases much more quickly than the CPUC can move. So I just wanted to make that comment, thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Others?

Is there any questions on the telephone? Questions on the telephone? No.

A fulsome day. Commissioner Geesman, any concluding comments?

ASSOCIATE MEMBER GEESMAN: I thought it was an outstanding workshop. I want to compliment all of you for your input to us today and I can assure you that it will be well received. We'll go over various written materials, review the transcript and I think give it a lot of thought in drafting the report that ultimately will come out this fall. I again want to thank you very much.

PRESIDING MEMBER PFANNENSTIEL: And I'll add my thanks to those. If there is any problem with today's workshop it was that it was almost too meaty. There's a lot going on in this field and we need to be able to digest it and apply it to some of the many problems and issues that we face.

But clearly we have a deep record, both

technical and I think a lot of policy guidance here so thank you all. I thank the staff. I think you did a great job in pulling this together so thank you very much.

MS. KELLY: Could I just say one thing? If anybody has written comments that they would like to provide after this workshop if you could provide them to me within, not this week but obviously by the end of next week we'd be glad to see them. Thank you very much.

PRESIDING MEMBER PFANNENSTIEL: All right, we'll be adjourned.

(Whereupon, at 4:33 p.m., the Committee workshop was adjourned.)

--o0o--

CERTIFICATE OF REPORTER

I, JOHN COTA, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 21st day of May, 2007.